2023-2025 Wildfire Mitigation Plan R1

Pacific Gas and Electric Company®

April 6, 2023

Docket Title: 2023 to 2025 Electrical Corporation Wildfire Mitigation Plans
Docket #: 2023-2025-WMPs

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PACIFIC GAS AND ELECTRIC COMPANY

2023-2025 WILDFIRE MITIGATION PLAN

SECTION 1

EXECUTIVE SUMMARY

1. Executive Summary

In the opening section of the WMP, the electrical corporation must provide an executive summary that is no longer than 10 pages.

The electrical corporation must provide a brief overview of its progress in achieving the goals, objectives, and targets specified in the previous WMP submissions. The overview must discuss areas of success, areas for improvement, and any major lessons learned.

The electrical corporation must summarize the primary goal, plan objectives, and framework for the development of the WMP for the 3-year cycle. The electrical corporation may use a combination of brief narratives and bulleted lists.

Introduction

Our stand is that catastrophic wildfires shall stop. In 2022, Pacific Gas and Electric Company (PG&E) continued to reduce wildfire ignition risk through our 2022 Wildfire Mitigation Plan (WMP) initiatives, such as Enhanced Powerline Safety Settings (EPSS) and undergrounding. We also reduced the customer impacts of programs such as EPSS. Our 2023 WMP builds on the work we have done to reduce wildfire risk by incorporating more mitigation work that targets the highest risk -informed areas of our system using existing mitigations measures and innovative technologies. Our plan also includes more community engagement opportunities that will facilitate reducing community impacts from mitigation work and safety outages.

Over the last several years, we have developed an integrated strategy to manage and reduce ignition risk. First, we have deployed a suite of Comprehensive Monitoring and Data Collection programs, such as wildfire cameras and asset inspections designed to provide insight into changing environmental hazards around our assets. These programs provide continuous monitoring capability that we use to decide what mitigations to deploy and where and when to deploy them.

Second, our integrated strategy also includes Operational Mitigations—like EPSS and Downed Conductor Detection—that provide on-going risk reduction and influence how we manage the environment around the electric grid. Operational mitigations also include initiatives we undertake to support customers before, during, and after wildfire events.

Third, we are deploying System Resilience mitigations such as our 10,000-mile distribution undergrounding program and our transmission line removal work to reduce ignition risk by changing how our grid is constructed and operated.

Finally, in addition to our mitigation initiatives, we regularly engage with our customers and communities to address issues related to wildfire preparation, ongoing safety work, and other public safety and preparedness issues.

Our strategies and programs are working. As we explain more below, in 2022, we significantly reduced California Public Utilities Commission (CPUC)-reportable ignitions in the High Fire Threat Districts (HFTD) and High Fire Risk Areas (HFRA) throughout our service area. We plan to continue these efforts in 2023 through EPSS, our undergrounding program, integrating more sophisticated risk-informed decision making into our risk management and mitigation planning, addressing vegetation risk on a more efficient, risk-informed basis, and ensuring that our public safety partners and customers are well prepared for Public Safety Power Shutoff (PSPS) events.

Our 2023 WMP reflects feedback from stakeholders including our customers, public safety partners, the Office of Energy Infrastructure Safety (Energy Safety), the CPUC, the Independent Safety Monitor, the Governor's Operational Observer, Community-Based Organizations, and the communities they serve, tribal governments, municipalities, and other engaged stakeholders.

Reducing Ignitions in the HFTD and HFRA

In 2022, our expanded EPSS Program significantly increased customer protection from wildfire ignitions. After launching as a pilot in 2021, the 2022 EPSS Program expanded substantially, protecting customers served by more than 44,000-line miles, including all high fire-risk areas.

The 2022 EPSS Program resulted in fewer CPUC-reportable ignitions and a reduction in acres impacted. We saw a **68 percent reduction** in reportable ignitions on primary distribution conductor when enabled, weather normalized, and a **99 percent reduction** in acres impacted compared to a 2018-2020 3-year average. Moreover, the average duration of an EPSS outage in 2022 was **56 percent less** than the average duration in 2021. In addition to EPSS, we are implementing other mitigations that we expect to result in reduced ignitions in HFTD and HFRA areas. For example, we are continuing to remove non-exempt equipment and expulsion fuses, installing additional covered conductor, installing system automation devices such as fuse savers, deploying remote grids, and installing break-away connectors. As we implement these mitigation measures in 2023, we expect to maintain the 2022 reductions in CPUC-reportable ignitions and to further reduce wildfire risk.

Aggressively Reducing Wildfire Risk in the HFTD and HFRA Through Undergrounding

In July 2021, we announced our multi-year 10,000-mile undergrounding program. Since that time, we have been putting in place the processes, tools, and team we need to execute this ambitious program. We saw the benefits of this effort in 2022 when we undergrounded approximately 180 miles, approximately **146 percent more** than the 73 miles undergrounded in 2021.

We will continue to build on this progress during the WMP cycle by undergrounding 2,100 miles of distribution lines in the HFTD from 2023 to 2026, effectively eliminating the ignition risk for overhead lines in those areas.

In this WMP, we are reducing the number of 2023-2026 undergrounding miles we had forecasted in the 2022 WMP. The current multi-year plan is consistent with our commitment to efficiently implement undergrounding. The reduced pace will decrease costs in the program's initial years and balance PG&E's planned work scope with meaningful risk reduction in the highest wildfire risk areas.

Between 2023 and 2026, **87 percent** of PG&E's undergrounding work is planned for the top 20 percent of risk-ranked circuit segments, as identified by our risk models.

Integrating More Sophisticated Risk-Informed Decision-Making into Our Risk Management and Mitigation Planning

In 2022, we updated our Wildfire Distribution Risk Model (WDRM) to WDRM version 3 (WDRM v3) and introduced version 1 of our Wildfire Transmission Risk Model (WTRM).

Our updated WDRM provides predictions of the where, why, and how much wildfire risk occurs during a typical wildfire season. The WDRM v3 quantifies risk for additional risk drivers compared to the previous version (WDRM version 2) and incorporates several improvements. The WDRM v3:

- Expands the machine learning to predict ignitions in the HFTD;
- Differentiates risk by location and/or individual assets so that we can prioritize higher-risk areas;
- Helps us understand the factors contributing to risk by modeling relationships among risk, environmental characteristics, and asset characteristics;
- Improves the consequence portion of the model; and
- Estimates where specific mitigations are likely to be most effective.

The 2023 WMP reflects the benefits of our improved risk modeling. We are using the outputs from the WDRM v3 to inform our risk-prioritized workplans for system hardening, Vegetation Management (VM) work, inspections, and maintenance activities. In addition, we are using the WTRM to inform our risk-prioritized workplans for certain types of inspections. In this way, we target work and programs that will provide the greatest risk reduction for our customers.

Addressing Vegetation Risk More Efficiently Through New Risk-Informed Mitigation Initiatives

In 2023, we are restructuring our VM Program based on a risk-informed approach. Recent data and analysis demonstrate that the Enhanced Vegetation Management (EVM) Program risk reduction is less than EPSS and additional Operational Mitigations such as Partial Voltage Detection capabilities. As a result, we transitioned the EVM Program to three new risk-informed VM programs.

- <u>Focused Tree Inspections</u>: We developed specific areas of focus (referred to as Areas of Concern (AOC)), primarily in the HFRA, where we will concentrate our efforts to inspect and address high-risk locations, such as those that have experienced higher volumes of vegetation damage during PSPS events, outages, and/or ignitions.
- <u>VM for Operational Mitigations</u>: This program is intended to help reduce outages and potential ignitions using a risk informed, targeted plan to mitigate potential vegetation contacts based on historic vegetation caused outages on EPSS-enabled

circuits. We will initially focus on mitigating potential vegetation contacts in circuit protection zones that have experienced vegetation caused outages. Scope of work will be developed by using EPSS and historical outage data and vegetation failure from the WDRM v3 risk model. EPSS-enabled devices vegetation outages extent of condition inspections may generate additional tree work.

- Tree Removal Inventory: This is a long-term program intended to systematically work down trees that were previously identified through EVM inspections. We will develop annual risk-ranked work plans and mitigate the highest risk-ranked areas first and will continue monitor the condition of these trees through our established inspection programs.

Preparing for and Improving Our Response to PSPS Events

In 2022, we successfully executed annual PSPS drills and Full-Scale Exercise (FSE) with our external partners. During the FSE, we simulated a PSPS event to test our PSPS processes and tools, and to train our emergency response team members who are responsible for responding to a PSPS event. As we explain in more detail in Section 10, we are using the lessons learned from the FSE to further improve our PSPS Program.

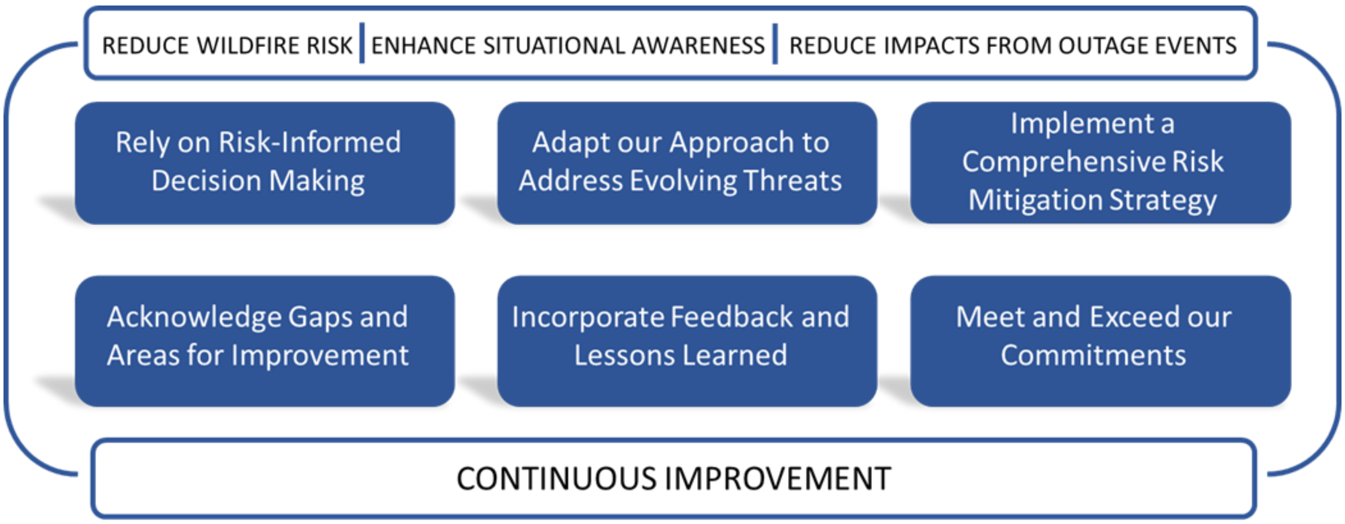
1.1 Summary of the 2020-2022 WMP Cycle

Consistent with California Law, we made substantial progress during the 2020-2022 WMP cycle constructing, maintaining, and operating our electrical lines and equipment in a manner to minimize the risk of catastrophic wildfires. Significant achievements include:

- Improving the models that we rely on to risk-inform our mitigation portfolio;
- Increasing our situational awareness;
- Adapting to changing climate conditions with new programs and mitigations;
- Implementing mitigation measures that reduced the potential for a wildfire ignition;
- Adopting EPSS throughout our HFTD and HFRA areas and improving response times to outages; and
- Improving reliability and customer and community impacts by significantly reducing the scope of PSPS outages.

Even with the progress we have made, we know that have more work to do. Figure PG&E-1.1-1 summarizes our 2020-2022 WMP objectives and the components of our risk mitigation strategy

FIGURE PG&E-1.1-1:
PG&E'S 2020-2022 WMP OVERALL OBJECTIVES AND
RISK MITIGATION STRATEGY COMPONENTS



Below, we describe each of the components of our 2020-2022 WMP strategy.

Rely on Risk-Informed Decision Making

During the 2020-2022 WMP cycle, we significantly advanced our risk modeling capabilities for informing work plans and mitigation initiative selections. Starting in 2019 with the WDRM version 1 (v1) we derived ignition probability from outage and ignition data using a logistical regression model. Wildfire consequence predictions came from fire modeling software. The WDRM v1 supported mitigation work conducted from 2019 to 2021.

WDRM (v2) took a significant step forward by using more advanced modeling, examining more sub-drivers with regards to ignitions, and using PG&E's Multi-Attribute Value Function to predict wildfire consequences. WDRM v2 also used more sophisticated algorithms, machine learning, and physics-based fire simulation outputs mapped into fire size/severity tranches to quantify wildfire consequence. WDRM v2 supported emergent mitigation work in 2021 and 2022 planned work.

WDRM v3 made improvements based on discussions with Energy Safety and review and feedback from internal and external experts. WDRM v3 uses more-advanced machine-learning modeling techniques, incorporates improved and updated data, adds predictions of wildfire risk reduction when mitigating various sources of risk, and expands to understand additional ignition sources and sub-drivers. WDRM v3 also includes "causal pathways" to ignitions, allowing for the nature of these causes to inform the type of model structure and relevant covariates. The WDRM v3 supports 2023 emergent work and our 2024-2026 planned work.

In 2022, we expanded our risk modeling capabilities by also introducing our first WTRM.

Adapt our Approach to Address Evolving Threats

We continually evaluate our wildfire mitigation approach to adapt to evolving wildfire threats. Since submitting our 2020 WMP, we have introduced new mitigations to better address and mitigate ignition risk and retired others that were no longer as effective.

In 2019, PSPS was our best response to protect the public when weather or other circumstances threatened our ability to provide electricity safely. However, while extremely effective at reducing wildfire risk, PSPS outages are disruptive. In 2020, we implemented PSPS impact initiatives such as transmission and distribution line sectionalizing and improved granularity in meteorological guidance tools. In 2021, we targeted mitigations to those locations that were most likely to be impacted by PSPS. The total customers impacted decreased by approximately **67 percent** from 2019 to 2021 and the total customer minutes of interruption decreased by approximately **97 percent** during this period.

As another example of our adaptive approach, in 2021, we implemented an EPSS pilot program that resulted in a significant reduction in ignitions. Given the success of the pilot, we fully operationalized the program in 2022. We made more than 44,000-line miles—including all high fire-risk areas—EPSS-capable, and we saw a dramatic **36 percent** reduction in CPUC-reportable ignitions in the HFTD, compared to the 2018-2020 3-year average. At the same time, average outage times and the number of customers affected per outage fell significantly from 2021.

Implement a Comprehensive Mitigation Strategy

Throughout the 2020-2022 WMP cycle, we presented a comprehensive mitigation strategy focused on addressing the greatest threats to both our system and our customers. We have relied on our increasingly sophisticated risk-modeling and tools to identify the locations where specific failures can lead to ignitions that have the highest consequences. Leveraging our risk analysis and governance processes, we developed a balanced portfolio of mitigation initiatives designed to address key risk drivers in the highest risk locations.

We also implemented programs such as undergrounding, system hardening, EVM, PSPS, and EPSS. Along with these foundational programs we built out our mitigation portfolio to improve our situational awareness capabilities, developed risk-based distribution, transmission, and substation inspection and maintenance programs. We also introduced new programs based on innovative technologies such as Supervisory Control and Data Acquisition (SCADA)-enabled automated sectionalizing devices and SmartMeter™ Partial Voltage Detection.

Acknowledge Gaps and Areas for Improvement

In 2020, we acknowledged shortcomings in several programs where improvement was needed. The feedback we received from Energy Safety and other stakeholders was helpful in shaping our 2021 WMP.

In 2021, we submitted notices to the CPUC regarding self-identified issues. These notices included gaps for enhanced inspections of hydroelectric substations, enhanced inspections for electric distribution poles, and accounting for the number of weather stations and high-definition cameras. We addressed these self-identified issues by instituting corrective action programs, implementing better controls, strengthening our asset registry, and instituting standardized counting procedures.

In 2022, we developed a plan to address our maintenance tag backlog for transmission and distribution facilities in the HFTD and HFRA areas. We are focused on completing the ignition-risk tags in the HFRA and HFTD areas and bundling other open notifications to efficiently address our gap in maintenance tag resolution.

Incorporate Feedback and Lessons Learned

Our WMPs incorporate feedback and lessons learned from the prior year. For example, in 2020, we recognized EVM was not aligned with our risk prioritization model. While not intentional, it reflected gaps in our processes. In 2021, we improved our process by updating our risk model, targeting EVM on the highest risk circuit segments, and implementing new governance procedures overseen by our Wildfire Risk Governance Steering Committee. In 2022, we completed 99.5 percent of our EVM work in the 20 percent highest risk-ranked circuits in the HFTD.

The lessons learned in 2021 involved three key themes: continued safety focus; coordination and knowledge sharing; and refining focus areas to our most effective core programs. We incorporated these lessons learned into our 2022 WMP.

Meet and Exceed our Commitments

Our 2020 WMP included 134 initiatives meant to reduce wildfire ignition potential, fire spread, and the impact of PSPS events. By the end of the year, we had successfully met over 90 percent of the initiative targets.[1] Despite the significant progress made during 2020, Energy Safety issued a Draft Annual Report on Compliance (ARC) for our 2020 WMP which found that PG&E did not substantially comply with the plan.[2] On December 27, 2022, we responded to Energy Safety that we strongly disagreed with this finding and urged that the Draft ARC be revised to indicate that PG&E substantially complied with the 2020 WMP.[3]

Our 2021 WMP included 53 commitments focused on wildfire mitigation activities such as risk modeling, system hardening, EVM, PSPS, and situational awareness. We completed all the commitments by year end 2021 and exceeded unit targets in several cases.

We identified 54 targets in our 2022 WMP and met or exceeded 52 of them. The two targets we did not meet in 2022 were associated with open distribution maintenance

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1 The methodology for this calculation is discussed in PG&E’s Comments on the Draft Annual Report on Compliance Regarding the 2020 Wildfire Mitigation Plan (Dec. 7, 2022), Docket #2020-ARC.

2 Draft Annual Report on Compliance for PG&E 2020 Wildfire Mitigation Plan (Dec. 5, 2022), Docket #2020-ARC.

3 PG&E’s Comments on the Draft Annual Report on Compliance Regarding the 2020 Wildfire Mitigation Plan (Dec. 7, 2022), Docket #2020-ARC.

tags and VM quality audits and reviews. While we were unable to close out as many lower risk E tags as anticipated, this was a result of emerging higher-risk A and B tags that were given priority. For VM, we completed all necessary audits and reviews contemplated in our target, but not all audits and reviews met the target of 95 percent Acceptable Quality Level. This occurred in part because the target was set in July at the request of Energy Safety after many of the audits and reviews had been performed. We are incorporating lessons learned from these two missed targets in our 2023 WMP.

Table PG&E-1.1-1, presented in Appendix F due to space limitations, lists the 42 quantitative targets that carried through the 2020-2022 WMP cycle and our progress against them.

1.2 Summary of the 2023-2025 Base WMP

Our primary goals for the 2023-2025 Base WMP are to:

- Construct, maintain, and operate our electrical lines and equipment in a manner that will minimize the risk of catastrophic wildfire posed by them;
- Thoroughly assess our wildfire risk, develop a comprehensive strategy to reduce ignitions, and ensure the reliability of the electric systems;
- Implement mitigations designed to minimize the likelihood of catastrophic wildfires; and
- Implement programs to limit customer disruption from our wildfire mitigation efforts.

PG&E's objectives over the 2023-2025 WMP cycle are to use risk-informed decision-making to minimize ignition risk and outage impacts. We have developed a balanced portfolio of mitigations centered around comprehensive monitoring and data collection, operational mitigations, and system resilience that work together to reduce wildfire risk and strengthen the resiliency of our electric distribution and transmission systems.

Figure PG&E-1.2-1 below shows our general WMP objectives and the framework for how we developed our plan within that framework.

FIGURE PG&E-1.2-1:
PG&E'S 2023-2025 WMP FRAMEWORK AND OBJECTIVES

Risk Informed-Decision Making

We will use our wildfire distribution, wildfire transmission, PSPS, and other risk models to make risk-informed decisions, ensuring that we are prioritizing our resources and efforts to reduce highest risk in the HFTD and HFRA and lessen impacts from wildfires and outages.

Comprehensive Monitoring and Data Collection

- Gain insight into the current state of our electrical systems
- Help us to proactively identify and address issues to reduce ignition risk
- Information and Data Collection includes programs such as Fire Detection and Alerting System and Asset Inspections

Operational Mitigations

- We rely on operational mitigations to manage our current risk on the system while we implement longer-term improvements to permanently reduce risk
- Operational Mitigations include programs such as Downed Conductor Detection and Life Extension Application for Transmission Line Assets

System Resilience

- Mitigations designed to reduce risk in the HFTD and HFRA by changing how our electric system are constructed and operated
- System Resilience mitigations include programs such as Transmission Pole/Tower Replacement and Reinforcements and HFTD/HFRA Open Tag Reduction

Community Impacts

- Reduce customer and community impacts related to wildfire emergencies and PSPS and EPSS outages
- Mitigation programs designed to reduce wildfire and outage related customer impacts
- We host safety-focused community engagement events to convey wildfire safety information before, during, and after wildfire events

Using this framework, we have identified 62 initiative targets and objectives that we will track throughout the year and report on quarterly and annually. In selecting these targets, we have chosen to focus on initiatives that will have the most significant impact on reducing wildfire risk and decreasing customer impacts from wildfire safety-related outages. We have completed certain programs and removed some less impactful targets from the 2023 WMP. As a result, the number of targets in the 2023 WMP is less than the number of targets in our 2022 WMP. We are confident that the work we will perform from 2023-2025 represents the right balance of mitigations to address the evolving wildfire risk.

Our 2023 WMP provides detailed tables describing each target in the sections prescribed by Energy Safety. In addition to the targets, we also have objectives associated with many of our mitigations. We highlight key objectives aligned to our framework below.

Risk-Informed Decision Making

Our Risk Methodology and Assessment Improvement Plan activities described in Section 6.7 incorporate important new data into the WDRM that will better represent items such as wildfire risk to vulnerable communities and the ability of a community to safely evacuate from an active wildfire.

Comprehensive Monitoring and Data Collection

In Section 8.3, we discuss our Situational Awareness and Forecasting objective to enable Artificial Intelligence (AI) processing of Wildfire Camera Data to provide automated wildfire notifications in the internal PG&E monitoring tool (Wildfire Incident

Viewer – WIV). Early detection of new ignitions can help reduce the overall impact of the ignition through increased awareness and more rapid response.

In Section 8.1.3, we describe our plan to increase retention for trained and qualified inspectors. Our plan focuses on increasing and sustaining a consistent, year-over-year internal workforce that builds on existing experience and mentors new employees for asset inspections.

Operational Mitigations

We will identify VM AOCs that will be primarily focused on HFRA as discussed in Section 8.2.3.4. A collaborative, cross-functional team will evaluate the service territory with electric overhead assets and create a system-wide map that includes VM AOCs. Starting in 2023 we will stand up a pilot program AOC in HFRA, barring external factors.

System Resilience Mitigations

Grid Design, Operations and Maintenance initiatives include system resilience programs such as Undergrounding and System Hardening. Key objectives include incorporating the findings from the joint utility covered conductor effectiveness study into maintenance and inspection standards. We discuss the covered conductor effectiveness study in ACI PG&E-22-11.

Community Impacts

In Section 8.4 we describe our Emergency Preparedness Plan objectives that include additional emergency training and exercises, coordinating emergency and disaster preparedness plans with external stakeholders, and participating in benchmarking for major outages. We will coordinate a variety of community engagement meetings in the five regions we serve. We describe these outreach efforts in Section 8.5.

2023 Wildfire Mitigation Maturity Survey

As described above, PG&E has and will continue to make progress in mitigating wildfire and ignition risk. We continue to support using, and refining, a wildfire mitigation capability maturity model to measure this progress. The maturity model helps us identify and share best practices and continually improve our approach to mitigate the risk of utility-caused wildfires.

This year's maturity model survey is significantly different from the previous survey, and thus the scores from this year cannot reasonably be compared to scores from prior years. Further, with this year's maturity model including questions that are not always relevant to utility operations, expectations that may be operationally impractical, and a new minimum scoring methodology, the scores do not accurately capture all of our actual and expected maturity, especially as to reducing wildfire risk.

We have made significant advancements in executing our wildfire mitigation plans and are seeing the benefits described throughout this WMP. The initiatives included in this WMP will further reduce wildfire risk and limit disruption from wildfire mitigation efforts for the benefit of our customers and communities throughout California.

PACIFIC GAS AND ELECTRIC COMPANY

2023-2025 WILDFIRE MITIGATION PLAN

SECTION 2

RESPONSIBLE PERSONS

2. Responsible Persons

The electrical corporation must list those responsible for executing the Wildfire Mitigation Plan (WMP), 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 WMP.*

Titles, credentials, and components of responsible person(s) must be released publicly. Electrical corporations can reference the WMP Process and Evaluation Guidelines and the California Code of Regulations Title 14 Section 29200 for the submission process of any confidential information.

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 for each component plan. Several program owners appear multiple times in the table. We have provided the credentials for each program owner only the first time they are listed.

TABLE PG&E-2-1:
PROGRAM OWNERS FOR EACH COMPONENT OF PLAN

Section	Name	Title	Credentials	Component
Section 1: Executive Summary	Andy Abranches	Sr. Director, Wildfire Risk Management	Mr. Abranches holds a Bachelor's degree in Mechanical Engineering from California Polytechnic State University, San Luis Obispo. He is also a graduate from General Electric Company's (GE) Technical Leadership Program and is a GE Certified Six Sigma Master Black Belt. Since joining Pacific Gas and Electric Company (PG&E or the Company) in 2008, Mr. Abranches has served in various leadership roles within Enterprise and Operational Risk, Electric Operations, Gas Operations, Finance, and Human Resources.	Section 1: All Components
Section 2: Responsible Persons	Jay Leyno	Director, Community Wildfire Safety Program (CWSP)	Mr. Leyno holds a Bachelor of Science in Business Management from the University of Phoenix. He has over 25 years of expertise in the utility field. He has served in a variety of roles of leadership roles in PG&E since 2014 and has been the Director for the CWSP for the past year.	Section 2: All Components
Section 3: Statutory Requirements Checklist	Anne Beech	Director, Regulatory Compliance and Investigation	Ms. Beech holds a Bachelor's degree in Business Administration/Accounting from San Francisco State University. She earned her Master of Business Administration (MBA) from St. Mary's College in Moraga, California and has participated in several executive leadership training programs. Since joining PG&E in 2000, Ms. Beech has held leadership roles in Customer Care, Gas Operations, Finance, and Information Technology. Currently she leads the Electric Operations California Public Utilities Commission (CPUC or Commission)/Office of Energy Infrastructure Safety (OEIS or Energy Safety) Compliance team, Wildfire Order Instituting Investigation Compliance team, and Data Response Unit.	Section 3: All Components
Section 4: Overview of WMP	Jay Leyno	Director, CWSP	Provided above	Section 4.1: Primary Goal
	Andy Abranches	Sr. Director, Wildfire Risk Management	Provided above	Section 4.2: Plan Objectives
	Matthew Whorton	Director, Business Finance Electric Operations and Engineering Strategy	Mr. Whorton has a MBA degree and a Bachelor of Science degree in Microbiology. He has 13 years of utility finance experience.	Section 4.3: Proposed Expenditures

TABLE PG&E-2-1:
PROGRAM OWNERS FOR EACH COMPONENT OF PLAN
(CONTINUED)

Section	Name	Title	Credentials	Component
	Paul McGregor	Director, Risk Management and Analytics	Mr. McGregor is the Director of Risk Management and Analytics, which includes: Wildfire Risk Management; Electric Asset Safety & Risk Management; and Risk and Data Analytics. He has over 30 years of experience working for, and consulting for, electric utilities in their operations, finance, and risk management matters across generation, transmission, distribution, energy marketing, customer service and corporate service functions. Mr. McGregor holds a Bachelor of Science degree in Technology and Business Studies from the University of Strathclyde and an MBA degree from the University of Pittsburgh.	Section 4.4: Risk-Informed Framework
Section 5: Overview of the Service Territory	Jadwindar Singh	Director, Asset Knowledge Management	Mr. Singh holds a Bachelor's degree in electrical engineering from California Polytechnic State University San Luis Obispo and is a Registered Professional Engineer in the state of California. He has held roles of increasing responsibility in electric operations including compliance management, risk management, asset management, and data management and analytics.	Section 5.1: Service Territory Section 5.2: Electrical Infrastructure Section 5.3.3: High Fire Threat Districts Section 5.3.5: Topography Section 5.4.1: Urban, Rural and Highly Rural Customers Section 5.4.2: Wildland-Urban Interface Section 5.4.3.1: Individuals at Risk from Wildfires Section 5.4.4: Critical Facilities and Infrastructure at

TABLE PG&E-2-1:
PROGRAM OWNERS FOR EACH COMPONENT OF PLAN
(CONTINUED)

Section	Name	Title	Credentials	Component
				Risk from Wildfire
	Shawn Holder	Director, Public Safety Power Shutoff (PSPS)	Mr. Holder holds a Bachelor's and Master's degree in Electrical Engineering from the University of Idaho. He has a certificate of Strategic Decision and Risk Management from Stanford. He is a Registered Professional Engineer in the state of California. Mr. Holder has held roles of increasing responsibility in electric operations and risk management.	Section 5.3.1: Fire Ecology Section 5.4.2: Wildland Urban Interface
	Andy Abranches	Sr. Director, Wildfire Risk Management	Provided above	Section 5.3.2: Catastrophic Wildfire History
	Nathan Bengtsson	Senior Manager, Climate Resilience	Mr. Bengtsson holds a Bachelor of Arts degree in International Relations from Claremont McKenna College and is a graduate of the CORO Fellows Program in Public Affairs. He has spent the last seven years with PG&E focused on climate policy, representing the Company at the California Air Resources Board, California Energy Commission, CPUC, and many other state agencies. He is the Senior Manager of Climate Resilience for PG&E.	Section 5.3.4.1: General Climate Conditions
	Harsh Grover	Senior Director, System & Resource Planning	Ms. Grover has 20 years of experience working in consulting, semiconductor, and utility industries in various operations, finance, and technology roles. She has been with PG&E for past 13 years and currently leads the System and Resource Planning in PG&E's Engineering, Strategy and Planning group. She holds a B.E. (Hons) in Computer Science from BITS, Pilani, India and a MBA degree in Strategy, Finance and Marketing from Brigham Young University in Utah.	Section 5.3.4.2: Climate Change Phenomena and trends
	Andy Abranches	Sr. Director, Wildfire Risk Management	Provided above	Section 5.4.3.2: Social Vulnerability and Exposure to Electrical Corporate Wildfire Risk Section 5.4.5: Environmental Compliance and Permitting

TABLE PG&E-2-1:
PROGRAM OWNERS FOR EACH COMPONENT OF PLAN
(CONTINUED)

Section	Name	Title	Credentials	Component
	Jadwindar Singh	Director, Asset Knowledge Management	Provided above	Section 5.4.3.2: Social Vulnerability and Exposure to Electrical Corporate Wildfire Risk
	Paul McGregor	Director, Risk Management and Analytics	Provided above	Section 5.4.3.3: Sub-Divisions with Limited Egress or No Secondary Egress
	James Merriman	Director, Underground, Grid & Permitting	Mr. Merriman holds a Bachelor's and Master's degree in Accounting from the University of Wisconsin-Madison. He has worked at PG&E for 11 years and has been a Director in Safety, Health, and Environmental Management for 5 years.	Section 5.4.5: Environmental Compliance and Permitting
Section 6: Risk Assessment and Methodology	Paul McGregor	Director, Risk Management and Analytics	Provided above	Section 6.1: Methodology Section 6.2: Risk Analysis Framework Section 6.3: Risk Scenarios Section 6.4.1.1: Geospatial Maps of Top-Risk Areas within HFRA Section 6.4.2: Top Risk-Contributing Circuits

				Section 6.6.1: Independent Review Section 6.6.2: Model Controls, Design, and Review Section 6.7: Risk Assessment Improvement Plan
	Shawn Holder	Director, PSPS	Provided above	Section 6.4.1.2: Proposed Updates to the HFTD
	Scott Strenfel	Director, Meteorology and Fire Science	Mr. Strenfel received his Bachelor of Science and Master of Science degrees in Meteorology from San Jose State University and was in the first graduating class of SJSU’s Fire Weather Research Laboratory. He leads a team of operational meteorologists and data scientists and is the Chief Meteorologist for PG&E.	Section 6.4.3: Other Key Metrics and Indicators
	Rick Ito	Sr. Director, Enterprise and Operational Risk Management (EORM)	Mr. Ito serves PG&E as the Senior Director for Enterprise Operations and Risk Management. He is responsible for risk management governance, risk regulatory strategy and enterprise risk analytics to manage the Company’s enterprise risks. Prior to joining PG&E Mr. Ito held several leadership positions in risk management and compliance. He holds Bachelor of Science and Master of Science degrees in Electrical Engineering from California State University (CSU), Long Beach and University of Southern California, respectively, and an MBA degree from the University of California at Los Angeles.	Section 6.5: Enterprise System for Risk Assessment
Section 7: Wildfire Mitigation Strategy Development	Jim Gill	Sr. Director, Asset Strategy Director, Transmission, Substation, and Storage Strategy	Mr. Gill holds a Bachelor of Science degree in Electrical Engineering from the University of Illinois, Champaign Urbana. He is a Registered Electrical Engineer, California with 23 years utility engineering, operations, and asset management experience.	Section 7.1.1: Approach Section 7.1.4: Mitigation Selection Process Section 7.1.4.1: Identifying and Evaluating Mitigation Initiatives

				Section 7.1.4.2: Mitigation Initiative Prioritization Section 7.1.4.3: Mitigation Initiative Scheduling Section 7.2.1: Overview of Mitigation Initiatives and Activities Section 7.2.3: Interim Mitigation Initiatives
	Maria Ly	Director, Transmission, Substation, and Storage Strategy	Ms. Ly is the Director of Transmission and Substation Asset Management at PG&E. She holds a Bachelor of Science degree in Electrical Engineering from California Polytechnic University (Cal Poly), San Luis Obispo, and is a California-Registered Professional Engineer. She has over 33 years of experience in the utility industry.	Section 7.1.1: Approach Section 7.1.4: Mitigation Selection Process Section 7.1.4.1: Identifying and Evaluating Mitigation Initiatives Section 7.1.4.2: Mitigation Initiative Prioritization Section 7.1.4.3: Mitigation Initiative Scheduling Section 7.2.1: Overview of Mitigation

				Initiatives and Activities Section 7.2.3: Interim Mitigation Initiatives
	Andy Abranches	Sr. Director, Wildfire Risk Management	Provided above	Section 7.1.2: Key Stakeholders for Decision Making Section 7.1.3: Risk Informed Prioritization Section 7.2.1: Overview of Mitigation Initiatives and Activities
	Jeff Deal	Vice President (VP), Electric Distribution Operations	Mr. Deal has a Bachelor of Science degree in Electrical Engineering from Cal Poly, San Luis Obispo. He is a Registered Professional Electrical Engineer in California and has 37 Years utility engineering and operational experience.	Section 7.1.4.3: Mitigation Initiative Scheduling
	Ahmad Ababneh	VP, Electric Operations (Ops), Projects & Construction	Mr. Ababneh has more than 25 years of experience focused on the energy and utility sectors. He holds a Bachelor's degree in Electrical Engineering from Jordan University of Science and Technology, a Master of Electrical Engineering degree from the University of New Orleans and a MBA degree from Palm Beach Atlantic University.	Section 7.1.4.3: Mitigation Initiative Scheduling
	Dave Gabbard	Sr. Dir, Transmission Substation Maintenance and Construction (M&C)	Mr. Gabbard holds a bachelor's degree in Mechanical Engineering from California Polytechnic State University San Luis Obispo. He also holds a MBA degree from University of Pennsylvania –The Wharton School. Mr. Gabbard is a certified Project Management Professional (PMP) from the Project Management Institute. He has 17 years of utility experience with PG&E and has held various roles in Project Management, Engineering, Construction, and Generation Interconnection. Mr. Gabbard is currently the Sr. Director for PG&E's Electric Transmission & Substation Department.	Section 7.1.4.3: Mitigation Initiative Scheduling
	Martin Wyspianski	VP, Electric Engineering, Asset & Regulatory	Mr. Wyspianski is the VP of Electric Engineering, Asset and Regulatory at PG&E. In this role, he is responsible for near-term engineering priorities and long-term planning, including asset and risk management for the utility's electric infrastructure.	Section 7.2.1: Overview of Mitigation Initiatives and Activities

	Paul McGregor	Director, Risk Management and Analytics	Provided above	Section 7.2.2: Anticipated Risk Reduction
Section 8: Wildfire Mitigations	Jay Leyno	Director, CWSP	Provided above	Section 8.1: Grid Design, Operations, and Maintenance All components
Section 8.1.2: Grid Design and System Hardening	Jim Gill	Sr. Director, Asset Strategy	Provided above	Section 8.1.2.6: Emerging Grid Hardening Technology Installations and Projects Section 8.1.2.6.1: Distribution, Transmission, and Substation: Fire Action Schemes and Technology Section 8.1.2.6.2: Breakaway Connector Section 8.1.2.10: Other Grid Topology Improvements to Minimize Risk of Ignitions Section 8.1.2.10.1: Downed Conductor Detection Devices Section 8.1.2.10.2: Installation of

				System Automation Equipment – Installation of Devices to Eliminate High Impedance Back-feed Conditions Section 8.1.2.10.3: Motor Switch Operator Switch Replacement Section 8.1.2.10.4: Surge Arresters Section 8.1.2.10.5: Non-Exempt Expulsion Fuses
	Matt Pender	Sr Director, Underground Program	Mr. Pender is PG&E's Senior Director of the Undergrounding Program. He joined PG&E in 2006 as a Gas Engineer and has previously held leadership positions in Gas Operations, Electric Operations, Land Management, Vegetation Management (VM), and Wildfire Risk Mitigation. Mr. Pender holds Bachelor of Science degrees in Mechanical Engineering and Business Management from North Carolina State University. He is a California registered Professional Engineer and has an MBA degree from the University of Pennsylvania's Wharton School of Business.	Section 8.1.2.1: Covered Conductor Installation Section 8.1.2.2: Undergrounding of Electric Lines and/or Equipment Section 8.1.2.5.2: Traditional Overhead Hardening – Distribution Section 8.1.2.9.2: Line Removal (in the HFTD) – Distribution

	Daniel Ohlendorf	Director, Work Readiness and Integration	Mr. Ohlendorf holds a Bachelor of Science in Aerospace Engineering, a Master of Engineering, and an MBA degree all from San Jose State University. He is also Project Management certified (PMP). Prior to serving as the Director of Work Readiness and Integration, he served previous roles at PG&E including the Director of Technology Program Management and various roles in Customer Care.	Section 8.1.2.3: Distribution pole replacements and reinforcements
	Joshua Fredriksson	Director, Contract Execution	Mr. Fredriksson has a Bachelor of Science degree in Supply chain Management and Logistics from California State University Maritime Academy. He has 14 years of utility experience overseeing, Project Management, Gas and Electric Design, Electric Vehicle, Wildfire Risk Mitigation, Vegetation and Construction. He currently supports all Major Events and PSPS activations as an Emergency Operations Center (EOC) Operations Section Chief.	Section 8.1.2.3: Distribution pole replacements and reinforcements
	Maria Ly	Director, Transmission, Substation, and Storage Strategy	Provided above	Section 8.1.2.4: Transmission Pole Replacements and Reinforcements Section 8.1.2.5.1: Traditional Overhead Hardening – Transmission Conductor Section 8.1.2.9.1: Line removal (in HFTD) – Transmission Section 8.1.2.11.1: Other Grid Topology Improvements to Mitigate or Reduce PSPS Events – Transmission Section 8.1.2.12.2: Other Technologies and Systems –

				Substation Animal Abatement
	Bob Brock	Director, T Line M&C	Mr. Brock has more than 39 years of utility experience as a Groundman, General Construction (GC) Apprentice Lineman, GC Lineman, GC Subforeman, T-200 Supervisor, T-300 Superintendent, Senior Manager of Distribution Work Methods & Procedures & Field Training and Director of T-Line M&C.	Section 8.1.2.4: Transmission Pole Replacements and Reinforcements
	Vanessa Morgan	Director, TS Project Mgt & Portfolio	Ms. Morgan holds a Bachelor's in Science degree in Business Communications from the University of Wyoming. She is also a graduate from Leadership California Program and is a Certified PMP. Ms. Morgan has 20 years of experience with PG&E and since 2012 she has served in various leadership roles within Standards & Work Methods and Electric Operations Project Management (Transmission, Distribution and Substation).	Section 8.1.2.5.1: Traditional Overhead Hardening – Transmission Conductor Section 8.1.2.9.1: Line removal (in the HFTD) – Transmission Section 8.1.2.11.1: Other Grid Topology Improvements to Mitigate or Reduce PSPS Events – Transmission Section 8.1.2.12.2: Other Technologies and Systems – Substation Animal Abatement
	Hicham Mejjaty	Director, Transmission and Distribution (T&D)	Mr. Mejjaty holds a Bachelor's degree in Electrical Engineering, Computer Engineering, and an MBA degree from Louisiana State University. He has 20 years of experience in the utility industry and has held multiple roles of increasing responsibility in Distribution Design, Distribution Planning and Reliability, Process Improvement, as well as Compliance and Risk Management	Section 8.1.2.6: Emerging Grid Hardening Technology Installations and Pilots

				Section 8.1.2.6.1: Distribution, Transmission, and Substation: Fire Action Schemes and Technology Section 8.1.2.6.2: Breakaway Connector Section 8.1.2.8: Installation of System Automation Equipment Section 8.1.2.8.1: Installation of System Automation Equipment – Distribution Protective Devices Section 8.1.2.10: Other Grid Topology Improvements to Minimize Risk of Ignitions Section 8.1.2.10.2: Installation of System Automation Equipment – Installation of Devices to Eliminate High Impedance Back-feed Conditions

				Section 8.1.2.10.3: Motor Switch Operator Switch Replacement Section 8.1.2.10.4: Surge Arresters Section 8.1.2.10.5: Non-Exempt Expulsion Fuses Section 8.1.2.11: Other Grid Topology Improvements to Mitigate or Reduce PSPS Events Section 8.1.2.11.2: Other Grid Topology Improvements to Mitigate or Reduce PSPS Events – Distribution Section 8.1.2.11.3: Other Grid Topology Improvements to Mitigate or Reduce PSPS Events – Substation
	Quinn Nakayama	Sr. Director, GRID Innovation Research and Development (R&D)	Mr. Nakayama holds a Bachelor of Science in Business Administration. He has 19 years of Utility experience of which 5 years have been spent in R&D Innovation.	Section 8.1.2.7: Microgrids Section 8.1.2.7.3: Community Microgrid

				Enablement Program (CMEP) and Microgrid Incentive Program (MIP) Section 8.1.2.7.4: Microgrid-Related Technology Pilots
	Mike Medeiros	Sr. Director, Electric Technology and Information Strategy	Mr. Medeiros holds of Bachelor of Science degree in Economics from Santa Clara University and a MBA from Golden Gate University. He has 32 years in the energy industry, with roles in energy efficiency, rate design, retail and wholesale energy marketing, gas pipeline and power plant development, transmission line and substation project management, and energy storage development.	Section 8.1.2.7.1: Remote Grids

TABLE PG&E-2-1:
PROGRAM OWNERS FOR EACH COMPONENT OF PLAN
(CONTINUED)

Section	Name	Title	Credentials	Component
	Satvir Nagra	Director, Asset Planning	Mr. Nagra has a Bachelor of Science in Electrical Engineering from Cal Poly San Luis Obispo and holds an active Professional Engineering License in Electrical Engineering for the state of California. He is the Director of Asset Planning within the Asset Management organization and has 31 years of experience. Mr. Nagra has held positions of increasing responsibility at PG&E focused on Electric Distribution Planning, Electric Transmission Planning, and Electric Generation Interconnection.	Section 8.1.2.8: Installation of System Automation Equipment Section 8.1.2.8.1: Installation of System Automation Equipment – Distribution Protective Devices Section 8.1.2.11: Other Grid Topology Improvements to Mitigate or Reduce PSPS Events Section 8.1.2.11.2: Other Grid Topology Improvements to Mitigate or Reduce PSPS Events – Distribution Section 8.1.2.11.3: Other Grid Topology Improvements to Mitigate or Reduce PSPS

				Events – Substation
	Dave Canny	Director, Electric Program Management	Mr. Canny has a Bachelor of Arts from Dartmouth College and a Master of Environmental Policy and Management from Duke University. He has a certificate of business excellence from the Haas School of Business at the University of California at Berkeley and is a graduate of the Utility Executive Course at the University of Idaho. Previous to his current role, Mr. Canny has held multiple roles of increasing responsibility in Customer Care and has extensive emergency response experience.	Section 8.1.2.10.1: Downed Conductor Detection Devices
	Calvin Black III	Director, M&C	Mr. Black holds a Bachelor of Science in Business Management, Black Belt in Lean Six Sigma, Total Quality Management Certification, Certified Electrical Technician, and Certified Electrician. He has served PG&E as a Journeyman Electrical Technician, Substation Maintenance Supervisor, Substation Maintenance and Construction Superintendent, Work Methods & Procedure Manager, and M&C Relay and Protection Manager.	Section 8.1.2.12.2: Other Technologies and Systems – Substation Animal Abatement
Section 8.1.3: Asset Inspections	Jim Gill	Sr. Director, Asset Strategy	Provided above	Section 8.1.3: Asset Inspections Section 8.1.3.2: Asset Inspections – Distribution Section 8.1.3.2.1: Detailed Ground Inspection Section 8.1.3.2.2: Infrared Inspections Section 8.1.3.2.3: Intrusive Pole Inspections Section 8.1.3.2.4: LiDAR-based Pole Loading Assessments Section 8.1.3.2.5: Overhead Equipment Inspections

				Section 8.1.3.2.6: Patrol Inspection Section 8.1.3.2.7: Pilot Inspections
	Heather Duncan	Director, System Inspections	Ms. Duncan has 32 years of experience at PG&E including roles in Customer Service, Meter Reader, Joint Pole, Mapper, Estimator, Supervisor, Distribution Specialist, and Production Specialist. Ms. Duncan started working in Compliance/Maintenance in 2001 and has held various roles and is currently the Director of System Inspections.	Section 8.1.3: Asset Inspections Section 8.1.3.2: Asset Inspections – Distribution Section 8.1.3.2.1: Detailed Ground Inspection Section 8.1.3.2.2: Infrared Inspections Section 8.1.3.2.3: Intrusive Pole Inspections Section 8.1.3.2.4: LiDAR-based Pole Loading Assessments Section 8.1.3.2.5: Overhead Equipment Inspections Section 8.1.3.2.6: Patrol Inspection Section 8.1.3.2.7: Pilot Inspections
	Maria Ly	Director, Transmission, Substation, and Storage Strategy	Provided above	Section 8.1.3.1: Asset Inspection Program – Transmission Section 8.1.3.1.1: Ground Detailed Inspection

				Section 8.1.3.1.2: Aerial Detailed Inspection Section 8.1.3.1.3: Climbing Detailed Inspection Section 8.1.3.1.4: Infrared Inspection Section 8.1.3.1.5: Intrusive Pole Inspections Section 8.1.3.1.6: Switch Function Testing Section 8.1.3.1.7: Patrol Inspection Section 8.1.3.1.8: Pilot Inspections Section 8.1.3.3: Asset Inspection Program – Substation Section 8.1.3.3.1: Substation Inspections
	Joshua Fredrickson	Director, Contract Execution	Provided above	Section 8.1.3.1: Asset Inspection Program – Transmission Section 8.1.3.1.1: Ground Detailed Inspection Section 8.1.3.1.2: Aerial Detailed Inspection

				Section 8.1.3.1.3: Climbing Detailed Inspection Section 8.1.3.1.4: Infrared Inspection Section 8.1.3.1.5: Intrusive Pole Inspections Section 8.1.3.1.6: Switch Function Testing Section 8.1.3.1.7: Patrol Inspection Section 8.1.3.1.8: Pilot Inspections Section 8.1.3.3: Asset Inspection Program – Substation Section 8.1.3.3.1: Substation Inspections
	Russ Cruzen	Director, Power Generation Asset Excellence	Mr. Cruzen has a Bachelor of Science in Electrical Engineering from Cal Poly San Luis Obispo and has a Professional Engineering License in Electrical Engineering for the state of California. Mr. Cruzen has extensive utility experience, including gas refining, nuclear engineering design, operations and maintenance, hydro construction, contracts, contractor safety and outage management.	Section 8.1.3.3: Asset Inspection Program – Substation Section 8.1.3.3.1: Substation Inspections
Section 8.1.4: Equipment Maintenance and Repair	Jim Gill	Sr. Director, Asset Strategy	Provided above	Section 8.1.4: Equipment Maintenance and Repair Section 8.1.4.1: Capacitors Maintenance

				Section 8.1.4.3: Connectors Maintenance (Including Hotline Clamps) Section 8.1.4.4: Conductors (Including Covered Conductors) Section 8.1.4.5: Fuses (Including Expulsion Fuses) Section 8.1.4.6: Distribution Poles Section 8.1.4.7: Lightning Arrestors Section 8.1.4.8: Reclosers Section 8.1.4.9: Splices Section 8.1.4.11: Transformers Section 8.1.4.12: Other Equipment Not Listed
	Bryon Winget	Sr. Director, WMP Tag Commitment Delivery	Mr. Winget holds a Bachelor and Master of Science degree in Material Science Engineering from University of California, Berkeley. He is also Project Management certified (PMP) and a certified Manager of Quality/Organizational Excellence. Prior to serving as the Sr. Director, WMP Tag Commitment Delivery, he served previous roles at PG&E including the Director of Gas Investment Planning and various Gas Engineering roles.	Section 8.1.4: Equipment Maintenance and Repair Section 8.1.4.4: Conductors (Including Covered Conductors)

				Section 8.1.4.5: Fuses (Including Expulsion Fuses) Section 8.1.4.10: Transmission Poles/Towers Section 8.1.4.11: Transformers Section 8.1.4.12: Other Equipment Not Listed
	Ryan Blake	Director, Distribution Programs	Mr. Blake is Director of Distribution Programs and has held the position for 2 years. He holds a Bachelor of Arts degree in Economics and Statistics from the University of California at Davis and has 12 years professional experience in utility operations and corporate finance. He served previous roles across construction and program management functions in Electric Operations.	Section 8.1.4.1: Capacitors Maintenance Section 8.1.4.3: Connectors Maintenance (Including Hotline Clamps) Section 8.1.4.9: Splices
	Maria Ly	Director, Transmission, Substation, and Storage Strategy	Provided above	Section 8.1.4.2: Circuit Breakers Maintenance Section 8.1.4.10: Transmission Poles/Towers
	Calvin Black III	Director, M&C	Provided Above	Section 8.1.4.2: Circuit Breakers Maintenance
	Hicham Mejjaty	Director, Transmission & Distribution	Provided Above	Section 8.1.4.6: Distribution Poles Section 8.1.4.7: Lightning Arrestors Section 8.1.4.8: Reclosers

Section 8.1.5: Asset Management and Inspection Enterprise System(s)	Jadwindar Singh	Director, Asset Knowledge Management	Provided above	Section 8.1.5: Asset Management and Inspection Enterprise System(s)
	Ali Moazed	Director, Data Management and Analytics	Mr. Moazed holds a Bachelor of Science degree in Civil Engineering from the University of Cincinnati, and a Master of Business Management and Master of Science in Sustainable Systems both from the University of Michigan. Since joining PG&E in 2009, Mr. Moazed has served in a variety of leadership roles including Finance, Customer Care, Smart Grid Strategy, Energy Procurement & Policy, Electric Emerging Technology, and Electric Data Management & Analytics teams.	Section 8.1.5: Asset Management and Inspection Enterprise System(s)
	Heather Duncan	Director, System Inspections	Provided above	Section 8.1.5: Asset Management and Inspection Enterprise System(s)
Section 8.1.6: Quality Assurance and Quality Control	Eric Thomas	Director, Compliance	Mr. Thomas has a Bachelor of Science degree in Aerospace Engineering and a Senior Reactor Operator's license issued from the Nuclear Regulatory Commission. He spent 12 years at Diablo Canyon in Operations with increasing responsibility and has spent the last 2 years in System Inspection Quality Control.	Section 8.1.6: Quality Assurance and Quality Control
Section 8.1.7: Open Work Orders	Maria Ly	Director, Transmission, Substation, and Storage Strategy	Provided above	Section 8.1.7.1: Open Work Orders – Transmission Tags Section 8.1.7.3: Open Work Orders – Substation Tags
	Bryon Winget	Sr. Director, WMP Tag Commitment Delivery	Provided above	Section 8.1.7.1: Open Work Orders – Transmission Tags Section 8.1.7.2: Open Work

				Orders – Distribution Tags Section 8.1.7.3: Open Work Orders – Substation Tags
	Jim Gill	Sr. Director, Asset Strategy	Provided above	Section 8.1.7.2: Open Work Orders – Distribution Tags
	Russ Cruzen	Director, Power Generation Asset Excellence	Provided above	Section 8.1.7.3: Open Work Orders – Substation Tags
Section 8.1.8: Grid Operations and Procedures	Dave Canny	Director, Electric Program Management	Provided above	Section 8.1.8.1: Equipment Settings to Reduce Wildfire Risk Section 8.1.8.1.1: Protective Equipment and Device Settings Section 8.1.8.1.2: Automatic Recloser Settings Section 8.1.8.1.3.2 Pole Mounted Sensor
	Satvir Nagra	Director, Asset Planning	Provided above	Section 8.1.8.1.3: Settings of Other Emerging Technologies Section 8.1.8.1.3.1: Rapid Earth Fault Current Limiter

				Section 8.1.8.1.3.3: Smart Tape
	Kari Chester	Director, Dispatch and Scheduling	Ms. Chester holds a Bachelor's degree in Organizational Communication and a MBA degree from Arizona State University. She has over 20 years of utility industry experience.	Section 8.1.8.2: Grid Response Procedures and Notifications
	Tracey Vardas	Director, Emergency Preparedness and Response (EP&R) Strategy and Execution (SE)	Ms. Vardas has a Bachelor of Science degree in Environmental Toxicology from the University of California at Davis. She has 28 years of experience in emergency management that includes: federal, state, county, city, and PG&E preparedness and response activities. As a professional emergency manager, she routinely responds to emergencies, including responding to the PG&E EOC and the California State Operations Center, and has help multiple positions within the Incident Command System.	Section 8.1.8.3: Personnel Work Procedures and Training in Conditions of Elevated Fire Risk
	Chris Steeb	Director, Aviation Services	Mr. Steeb has a degree from the University of San Diego and has been a helicopter pilot since 1994. Mr. Steeb has been an aviation manager in varying capacities including as Aviation Operation Supervisor for San Diego Gas & Electric Company and Aviation Program Manager for UCSF Benioff Children's Hospital. Mr. Steeb has been the Director of Aviation Services at PG&E since 2021.	Section 8.1.8.3: Personnel Work Procedures and Training in Conditions of Elevated Fire Risk
Section 8.1.9: Workforce Planning	Heather Duncan	Director, System Inspections	Provided above	Section 8.1.9.1: Workforce Planning – Asset Inspections
	Jason Regan	VP System Inspections	Mr. Regan has been the VP of Electric Transmission and Distribution (T&D) System Inspections since 2022 and previously was the Sr. Director of Inspections. He has 25 years of Utility Gas and Electric management and program execution experience. He has held multiple roles of increasing responsibility across many functional organizations, including: Gas, Emergency Response, Electric T&D Maintenance and Distribution Control Center Operations. He has served as our Incident Commander or Deputy Commander on all PSPS events and many other incident responses.	Section 8.1.9.1: Workforce Planning – Asset Inspections
	Rob Merrick	Director, Contract Construction	Mr. Merrick has 25 years of electric Transmission and Distribution experience. He has spent four years in Quality Assurance as Transmission Specialist auditing Distribution and Transmission maintenance programs and acting as a liaison with the CPUC during T&D compliance audits. Mr. Merrick was an Electric Client Manager in Supply Chain and was Logistics Chief for the base camp to support the restoration efforts during the Valley and Camp fire. He has held other various leadership roles in PG&E.	Section 8.1.9.2: Workforce Planning – Grid Hardening

	Jay De Alba	Director, GC	Mr. De Alba holds Bachelor of Science degree in Criminal Justice from CSU Sacramento. He has 34 years of experience in Transmission and Distribution Electric Construction.	Section 8.1.9.2: Workforce Planning – Grid Hardening
	Craig Kurtz	Sr. Director, Distribution Grid Operations	Mr. Kurtz holds a Bachelor of Science degree in Engineering and a MBA degree. He has had the privilege and honor of serving PG&E's customers for over 30 years.	Section 8.1.9.3: Workforce Planning – Risk Event Inspection
Section 8.2: Vegetation Management	Kamran Rasheed	Director, VM Operations	Mr. Rasheed is the Director of VM Asset Strategy and Analytics. He has 21 years of utility VM experience. He has held multiple roles of increasing responsibility in VM. He holds a Master of Science in Forestry degree and is a Certified Arborist/Utility Specialist, is Tree Risk Assessment Qualified, is a Certified Treecare Safety Professional, and a Certified Utility Safety Professional.	Section 8.2.1: Overview Section 8.2.1.1: Objectives Section 8.2.1.2: Targets Section 8.2.1.3: Performance Metrics Identified by the Electric Corporation Section 8.2.2: Vegetation Management Inspections Section 8.2.2.1: Vegetation Management Inspection Program – Transmission Section 8.2.2.1.1: Routine Transmission NERC and Non-NERC Section 8.2.2.1.2: Transmission Second Patrol

				Section 8.2.2.2: Vegetation Inspections – Distribution Section 8.2.2.2.1: Distribution Routine Patrol Section 8.2.2.2.2: Distribution Second Patrol Section 8.2.2.2.3: Discontinued Programs Section 8.2.2.3: Vegetation Inspections – Substations Section 8.2.2.3.1: Defensible Space Inspection Section 8.2.3: Vegetation and Fuels Management Section 8.2.3.1: Pole Clearing Section 8.2.3.2: Wood and Slash Management Section 8.2.3.5: Substation Defensible Space (Mitigation) Section 8.2.3.6: High-Risk Species

				Section 8.2.3.7: Fire-Resilient Right-of-Ways Section 8.2.3.3: Clearance Section 8.2.3.4: Fall-in Mitigation Section 8.2.3.8: Emergency Response Vegetation Management Section 8.2.4: Vegetation Management Enterprise System Section 8.2.5: Quality Assurance/ Quality Control Section 8.2.5.1: Quality Assurance and Quality Verification Section 8.2.5.2: Quality Control (QC) Section 8.2.6: Open Work Orders Section 8.2.7: Workforce Planning Section 8.2.7.1: Workforce Planning –

				Vegetation Inspections Section 8.2.7.2: Workforce Planning – Vegetation Management Projects
	Stephen Simon	Sr. Director, Quality	Mr. Simon has 10 years of experience at PG&E leading technical teams and developing specialized quality management systems across Gas Operations, VM, and System Inspections with the objective of ensuring safety, risk mitigation, compliance and continuous improvement. He holds a mechanical engineering degree, project management, engineering leadership and technical inspection certifications and currently leads the Major Infrastructure Development Quality Management organization at PG&E.	Section 8.2.1: Overview Section 8.2.1.1: Objectives Section 8.2.1.2: Targets
	Sara Carlson	Director, Programs, VM	Ms. Carlson has a Bachelor of Science degree from CSU East Bay, and 7 years of utility experience at PG&E starting in Gas Operations and transitioning to VM. She has served in a variety of roles of increasing responsibility supporting project controls, program management, and process improvement. She now holds the position of Director of the Program Management Organization for VM.	Section 8.2.1.3: Performance Metrics Section 8.2.6: Open Work Orders
	Kevin Buteau	Director, Execution South & Transmission	Mr. Buteau holds a Bachelor of Science in Forestry from the University of California at Berkeley. He has 25 years of utility VM experience. Mr. Buteau has held multiple roles of increasing responsibility within VM, and he is an International Society of Arboriculture ISA Certified Arborist Utility Specialist.	Section 8.2.2: Vegetation Management Inspections Section 8.2.2.1: Vegetation Management Inspection Program – Transmission Section 8.2.2.1.1: Routine Transmission NERC and Non-NERC Section 8.2.2.1.2: Transmission Second Patrol

				Section 8.2.2.2: Vegetation Inspections – Distribution Section 8.2.2.2.1: Distribution Routine Patrol Section 8.2.2.2.2: Distribution Second Patrol Section 8.2.2.2.3: Discontinued Programs
	Andy Abranches	Sr. Director, Wildfire Risk Management	Provided above	Section 8.2.2.3: Vegetation Inspections – Substations Section 8.2.2.3.1: Defensible Space Inspection
	Michael Koffman	Director, Business & Technical Services	Mr. Koffman has a Bachelor of Arts degree in English Literature from the University of Massachusetts. He is the Director of VM Business and Technology. Mr. Koffman has 20 years of experience in the utility industry where he has lead teams responsible for the development of capital infrastructure strategy, delivery of pole inspection, tree inspection, and tree work.	Section 8.2.3: Vegetation and Fuels Management Section 8.2.3.3: Clearance Section 8.2.3.4: Fall-in Mitigation Section 8.2.3.8: Emergency Response Vegetation Management Section 8.2.4: Vegetation Management Enterprise System

				Section 8.2.7: Workforce Planning Section 8.2.7.1: Workforce Planning – Vegetation Inspections Section 8.2.7.2: Workforce Planning – Vegetation Management Projects
	Don Parker	Director, Execution North	Mr. Parker has a Bachelor of Science degree in Mechanical Engineering from University of the Pacific. He has 23 years of engineering, project, program, and construction management experience. Prior to serving as the Director, Execution North, he served previous roles at PG&E including Construction Manager of Gas Operations, Regional Manager of Gas Operations-Bay Region, and Sr. Manager of Construction Management within VM.	Section 8.2.3.1: Pole Clearing
	John Fiske	Director of Execution, VM	Mr. Fiske is the Director for VM Execution, focusing on Wood Management. He has been with PG&E since 2012 and has held various leadership roles during that time. Mr. Fiske has 35 years operational experience in the Utility Industry.	Section 8.2.3.2: Wood and Slash Management
	Kevin Lieberman	Director, Quality Management	Mr. Lieberman is the Director of Quality Management in the VM Program. Previously, he was the Quality Manager of Gas T&D Construction, implementing multiple successful programs. He has 20+ years of quality related experience within the utility industry.	Section 8.2.5: Quality Assurance/ Quality Control
	Maria Ly	Director, Transmission, Substation, and Storage Strategy	Provided above	Section 8.2.3.5: Substation Defensible Space (Mitigation)
	Russ Cruzen	Director, Power Generation Asset Excellence	Provided above	Section 8.2.3.5: Substation Defensible Space (Mitigation)
	Aimee Crawford	Director, Land Management	Ms. Crawford holds a Bachelor of Arts degree from the University of California at Davis, and a Juris Doctor degree from the University of California College of the Law, San Francisco. She has over 20 years of expertise in a range of land management and land transactional work. She has served in a variety of roles in	Section 8.2.3.5: Substation Defensible Space (Mitigation)

			Land Management since 2011 and has been the Director for Land Management for the last 4 years.	
Section 8.3: Situational Awareness and Forecasting	Angie Gibson	VP, EP&R	Ms. Gibson has 35 years of experience within the utility and emergency management space. She currently oversees all areas of emergency management for the PG&E enterprise, including: mitigation, prevention, preparedness, response, and recovery. She received a Bachelor of Science degree in Public Safety Administration from Franklin University, Columbus, Ohio, in 2004. Ms. Gibson is a California State Certified Fire Fighter I, Federal Emergency Management Agency-certified Master Exercise Practitioner, and a Disaster Science Fellow of the Academy of Emergency Management. She is currently a member of third cohort of the Vanguard Senior Executive Crisis Leadership Program.	Section 8.3.1.1: Objectives Section 8.3.1.2: Targets Section 8.3.1.3: Performance Metrics Identified by the Electric Corporation Section 8.3.4: Ignition Detention Systems Section 8.3.4.5: Enterprise System for Ignition Detection
	Paul McGregor	Director, Risk Management and Analytics	Provided above	Section 8.3.1.1: Objectives Section 8.3.1.3: Performance Metrics Identified by the Electric Corporation
	Craig Kurtz	Sr. Director, Distribution Grid Operations	Provided Above	Section 8.3.1.2: Targets Section 8.3.3: Grid Monitoring Systems
	Scott Strenfel	Director, Meteorology and Fire Science	Provided Above	Section 8.3.2: Environmental Monitoring Systems Section 8.3.4: Ignition Detection Systems

				All components except for Section 8.3.4.5 Section 8.3.5: Weather Forecasting Section 8.3.6: Fire Protection Index
Section 8.4: Emergency Preparedness	Tracey Vardas	Director, Emergency Preparedness and Response Strategy and Execution	Provided above	Section 8.4.1: Overview Section 8.4.2: Emergency Preparedness Plan Section 8.4.2.1: Overview of Wildfire and PSPS Emergency Preparedness Section 8.4.2.3: Drills, Simulations, and Tabletop Exercises Section 8.4.2.4: Schedule for Updating and Revising Plan Section 8.4.3.1: Emergency Planning Section 8.4.3.3: Mutual Aid Agreements

				Section 8.4.5: Service Restoration Plan All Components
	Sandra Cullings	Sr. Director, (GC) and Contractors	Ms. Cullings has Bachelor of Arts degree in Political Science from Stanislaus State University. She has been with PG&E for over 20 years, primarily in Electric Operations work and resource management. She recently directed the Electric Work and Resource Planning function and has successfully led multiple work execution efforts in Electric Distribution, Wildfire and Transmission. She is a veteran of multiple EOC activations and multiple incident management teams most recently the Electric Work Execution Incident Management Team.	Section 8.4.2.2: Key Personnel, Qualifications, and Training
	Robert Cupp	Director, Emergency Field Operations	Mr. Cupp is a journeyman Lineman with 33 years of Electric T&D experience at various levels of leadership.	Section 8.4.2.2: Key Personnel, Qualifications, and Training
	Susie Martinez	Director, Liaison and Regulatory Operations	Ms. Martinez has 31 years of experience at PG&E, with a focus on customer service, community relations, finance, regulatory relations and compliance and emergency response. She leads a team responsible for stakeholder engagement, compliance, and liaison operations. She holds a bachelor's degree in Business Management from University of Phoenix.	Section 8.4.3.1: Emergency Planning Section 8.4.3.2: Communication Strategy with Public Safety Partners
	Chris Bober	Director, Cust Emergency Planning & Ops	Mr. Bober holds a Ph.D. in Organization Development from the University of Illinois, Champaign-Urbana. He is currently the Director of Customer Emergency Planning and Operations. He has been with PG&E, serving in a variety of roles, since 2000.	Section 8.4.4: Public Emergency Communication Strategy Section 8.4.6: Customer Support in Wildfire and PSPS Emergencies
Section 8.5: Community Outreach and Engagement	Chris Bober	Director, Cust Emergency Planning & Ops	Provided above	Section 8.5.1: Overview Section 8.5.2: Public Outreach

				and Education Awareness Program Section 8.5.3: Engagement with Access and Functional Needs Populations
	Susie Martinez	Director, Liaison and Regulatory Operations	Provided above	Section 8.5.4: Collaboration on Local Wildfire Mitigation Planning
	Jay Leyno	Director, CWSP	Provided above	Section 8.5.5: Best Practice Sharing with Other Electrical Corporations
Section 9: Public Safety Power Shutoff	Shawn Holder	Director, PSPS	Provided above	Section 9.1: Overview Section 9.2: Protocols on PSPS Section 9.3: Communication Strategy for PSPS Section 9.5: Planning and Allocation of Resources for Service Restoration Due to PSPS
	Chris Bober	Director, Cust Emergency Planning & Ops	Provided above	Section 9.3: Communication Strategy for PSPS

	Suzie Martinez	Director, Liaison and Regulatory Operations	Provided above	Section 9.3: Communication Strategy for PSPS
	Sandra Cullings	Sr. Director, GC and Contractors	Provided above	Section 9.4: Key Personnel Qualifications, and Training for PSPS
	Robert Cupp	Director, Emergency Field Operations	Provided above	Section 9.4: Key Personnel Qualifications, and Training for PSPS
	Tracey Vardas	Director, EP&R SE	Provided above	Section 9.4: Key Personnel Qualifications, and Training for PSPS
Section 10: Lessons Learned	Andy Abranches	Sr. Director, Wildfire Risk Management	Provided above	Section 10: Lessons Learned (1) Ongoing Internal Monitoring and Evaluations Initiatives (2) Feedback from Energy Safety, Industry Experts, and Stakeholders
	Jay Leyno	Director, CWSP	Provided above	Section 10: Lessons Learned (1) Ongoing Internal Monitoring and Evaluations Initiatives

				(2) Feedback from Energy Safety, Industry Experts, and Stakeholders
	Chris Bober	Director, Cust Emergency Planning & Ops	Provided above	Section 10: Lessons Learned Ongoing Internal Monitoring and Evaluations Initiatives
	Vince Tanguay	Sr. Director, Electric Compliance and Investigations	Mr. Tanguay has a Bachelor of Engineering (Mechanical), Master of Engineering (Mechanical) and a Doctorate of Mechanical Engineering from McGill University, Montreal, Canada. Prior to his current role of Sr. Director of Electric Compliance and Investigations, he has held roles of Sr. Director of Enterprise Compliance, Director of Risk and Compliance in Gas Operations, and a number of leadership roles in Gas Asset Knowledge Management.	Section 10: Lessons Learned Ongoing Internal Monitoring and Evaluations Initiatives
	Sean Mackay	Director, Investigations	Mr. McKay started at PG&E in 2016 in the Energy Efficiency Policy and Strategy group before moving to Electric Compliance in 2018. Previously, he was Manager of Federal Government Affairs for Sempra Energy. Mr. McKay has a Bachelor of Science degree from Cornell University in Biological and Environmental Engineering Technology.	Section 10: Lessons Learned Feedback from Energy Safety, Industry Experts, and Stakeholders
	Anne Beech	Director, Regulatory Compliance and Investigation	Provided above	Section 10: Lessons Learned Feedback from Energy Safety, Industry Experts, and Stakeholders
	Jim Gill	Sr. Director, Asset Strategy	Provided above	Section 10: Lessons Learned Feedback from Energy Safety, Industry Experts, and Stakeholders

Section 11: Corrective Action Program (CAP)	Sean Mackay	Director, Investigations	Provided above	Section 11: Corrective Action Program (1) Prevent Recurrence of Risk Events, (2) Address Findings from Wildfire Investigations (Both Internal and External)
	Anne Beech	Director, Regulatory Compliance, and Investigations	Provided above	Section 11: Corrective Action Program Address Findings from Energy Safety's Compliance Assurance Division
	Jay Leyno	Director, CWSP	Provided above	Section 11: Corrective Action Program Address Areas for Continuous Improvement (ACI) Identified by Energy Safety as Part of WMP Evaluation
Section 12: Notices of Violation and Defect	Anne Beech	Director, Regulatory Compliance and Investigations	Provided above	Section 12 All Components
Appendix B	Paul McGregor	Director, Risk Management and Analytics	Provided above	Appendix B All Components

Appendix D: Areas of Continuous Improvement	Paul McGregor	Director, Risk Management and Analytics	Provided above	Appendix D ACI PG&E-22-01 ACI PG&E-22-02 ACI PG&E-22-03 ACI PG&E-22-04 ACI PG&E-22-05 ACI PG&E-22-06 ACI PG&E-22-07 ACI PG&E-22-08 ACI PG&E-22-09 ACI PG&E-22-17 ACI PG&E-22-20 ACI PG&E-22-22 ACI PG&E-22-24 ACI PG&E-22-28 ACI PG&E-22-30 ACI PG&E-22-33 ACI PG&E-22-34
	Andy Abranches	Sr. Director, Wildfire Risk Management	Provided above	ACI PG&E-22-08 ACI PG&E-22-11
	Scott Strenfel	Director, Meteorology and Fire Science	Provided above	ACI PG&E-22-10
	Jim Gill	Sr. Director, Asset Strategy	Provided above	ACI PG&E-22-11 ACI PG&E-22-12 ACI PG&E-22-13 ACI PG&E-22-15 ACI PG&E-22-20 ACI PG&E-22-31

	Maria Ly	Director, Transmission, Substation, and Storage Strategy	Provided above	ACI PG&E-22-14
	Vanessa Morgan	Director, TS Project Mgt & Portfolio	Provided above	ACI PG&E-22-14
	Satvir Nagra	Director, Asset Planning	Provided above	ACI PG&E-22-15
	Hicham Mejjaty	Director, Transmission & Distribution	Provided above	ACI PG&E-22-15
	Matt Pender	Sr Director, Underground Program	Provided above	ACI PG&E-22-16
	Paul Standen	Sr Director, Underground Regional Delivery	Mr. Standen holds a Bachelor of Science in Business Administrative and Accounting and is a certified PMP. He has 12 years of utility experience primarily in Project Management and Leadership. Since 2020 he has led the project management team executing both System Hardening and Fire Rebuilds.	ACI PG&E-22-16
	Bryon Winget	Sr. Director, WMP Tag Commitment Delivery	Provided above	ACI PG&E-22-17 ACI PG&E-22-22
	Jason Regan	VP System Inspections	Provided above	ACI PG&E-22-18 ACI PG&E-22-19
	Heather Duncan	Director, System Inspections	Provided above	ACI PG&E-22-18 ACI PG&E-22-19
	Stephen Simon	Sr. Director, Quality	Provided above	ACI PG&E-22-21 ACI PG&E-22-26
	Kamran Rasheed	Director, VM Asset Strategy & Analytics	Provided above	ACI PG&E-22-23 ACI PG&E-22-25 ACI PG&E-22-27 ACI PG&E-22-29
	Don Parker	Director, Execution North	Provided above	ACI PG&E-22-23

	Sarah Carlson	Director, Programs, VM	Provided above	ACI PG&E-22-25
	Michael Koffman	Director, Business & Technical Services	Provided above	ACI PG&E-22-24 ACI PG&E-22-27 ACI PG&E-22-28 ACI PG&E-22-29
	Dave Canny	Director, Electric Program Management	Provided above	ACI PG&E-22-30 ACI PG&E-22-32
	Shawn Holder	Director, PSPS	Provided above	ACI PG&E-22-31 ACI PG&E-22-35
	Ali Moazed	Director, Data Management and Analytics	Provided above	ACI PG&E-22-33

PACIFIC GAS AND ELECTRIC COMPANY

2023-2025 WILDFIRE MITIGATION PLAN

SECTION 3

STATUTORY REQUIREMENT CHECKLIST

3. Statutory Requirements Checklist

This section provides a "checklist" of the statutory requirements for a WMP as detailed in Public Utilities Code (Pub. Util. Code) Section 8386®. By completing the checklist, the electrical corporation affirms that its WMP addresses each requirement.

For each statutory requirement, the checklist must include a reference and hyperlink to the relevant section and page number in the WMP. Where multiple WMP sections provide the information for a specific requirement, the electrical corporation must provide references and hyperlinks to all relevant sections. Unique references must be separated by semicolons, and each must include a brief summary of the contents of the referenced section (e.g., Section 5, pp. 30-32 [workforce]; Section 7, p. 43 [mutual assistance]).

Please see Table 3-1 below for our Statutory Requirements Checklist for the 2023 WMP.

TABLE 3-1:
STATUTORY REQUIREMENTS CHECKLIST

Pub. Util. Code Section 8386 (c)	Description	WMP Section and Page Number
1	An accounting of the responsibilities of person(s) responsible for executing the plan.	Section 2, pp.13 to 53 (responsible persons)
2	The objectives of the plan.	Section 4.1, p. 64 (primary goal) Section 4.2, pp. 65 to 66 (the objectives of the plan)
3	A description of the preventive strategies and programs to be adopted by the electrical corporation to minimize the risk of its electrical lines and equipment causing catastrophic wildfires, including consideration of dynamic climate change risks.	Section 6, pp. 133 to 222 (risk methodology and assessment) Section 7, pp. 224 to 316 (wildfire mitigation strategy development) Section 8, pp. 318 to 747 (wildfire mitigations) Section 9, pp. 749 to 784 (public safety power shutoff) Section 11, pp. 798 to 806 (corrective action program) Appendix D, pp. 856 to 974 (areas of continuous improvement)
4	A description of the metrics the electrical corporation plans to use to evaluate the plan's performance and the assumptions that underlie the use of those metrics.	Section 6.4.3, pp. 199 to 200 (other key metrics) Section 8.1.1.3, pp. 334 to 336 (performance metrics identified by the electrical corporation) Section 8.2.1.3, pp. 507 to 509 (performance metrics identified by the electrical corporation) Section 8.3.1.3, , pp. 572 to 574 (performance metrics identified by the electrical corporation) Section 8.4.1.3, pp. 632 to 634 (performance metrics identified by the electrical corporation) Section 8.5.1.3, pp. 727 to 728 (performance metrics identified by the electrical corporation) Section 9.1.5pp. 763 to 765 (performance metrics identified by the electrical corporation)

TABLE 3-1:
STATUTORY REQUIREMENTS CHECKLIST
(CONTINUED)

Pub. Util. Code Section 8386 (c)	Description	WMP Section and Page Number
5	A discussion of how the application of previously identified metrics to previous plan performances has informed the plan.	Section 6.4.3, pp. 199 to 200 (other key metrics) Section 8.1.1.3, pp. 334 to 336 (performance metrics identified by the electrical corporation) Section 8.2.1.3, , pp. 507 to 509 (performance metrics identified by the electrical corporation) Section 8.3.1.3, pp. 572 to 574 (performance metrics identified by the electrical corporation) Section 8.4.1.3, pp. 632 to 634 (performance metrics identified by the electrical corporation) Section 8.5.1.3, pp. 727 to 738 (performance metrics identified by the electrical corporation) Section 9.1.5, pp. 763 to 765 (performance metrics identified by the electrical corporation)
6	Protocols for disabling reclosers and de-energizing portions of the electrical distribution system that consider the associated impacts on public safety. As part of these protocols, each electrical corporation shall include protocols related to mitigating the public safety impacts of disabling reclosers and de-energizing portions of the electrical distribution system that consider the impacts on all of the aspects listed in Pub. Util. Code 8386 (c).	Section 8.1.4.8, p. 426 (reclosers) Section 8.1.8.1.2, p. 469 (automatic recloser settings) Section 9.2, pp. 766 to 783 (protocols on PSPS)
7	Appropriate and feasible procedures for notifying a customer who may be impacted by the de-energizing of electrical lines, including procedures for those customers receiving a medical baseline allowance as described in paragraph (6). The procedures shall direct notification to all public safety offices, critical first responders, health care facilities, and operators of telecommunications	Section 8.4.6, pp. 711 to 716 (customer support in wildfire and PSPS emergencies) Section 8.5, pp. 717 to 747 (community outreach and engagement) Section 9.3, p. 783 (communication strategy for PSPS)

TABLE 3-1:
STATUTORY REQUIREMENTS CHECKLIST
(CONTINUED)

Pub. Util. Code Section 8386 (c)	Description	WMP Section and Page Number
	infrastructure with premises within the footprint of potential de-energization for a given event.	
8	Identification of circuits that have frequently been de-energized pursuant to a de-energization event to mitigate the risk of wildfire and the measures taken, or planned to be taken, by the electrical corporation to reduce the need for, and impact of, future de-energization of those circuits, including, but not limited to, the estimated annual decline in circuit de-energization and de-energization impact on customers, and replacing, hardening, or undergrounding any portion of the circuit or of upstream transmission or distribution lines.	Section 9.1.2, pp. 751 to 755 (identification of frequently de-energized circuits) Section 9.2.2, pp. 775 to 778 (protocols on PSPS – method used to compare and evaluate the relative consequences of PSPS and wildfires) Section 9.2.3, pp. 779 to 781 (protocols on PSPS – outline of tactical and strategic decision-making protocol) Section 9.2.4, pp. 781 to 783 (protocols for mitigating the public safety impacts of PSPS)
9	Plans for VM.	Section 8.2, pp. 491 to 563 (VM and inspections)
10	Plans for inspections of the electrical corporation's electrical infrastructure.	Section 8.1.2, pp. 337 to 384 (grid design and system hardening) Section 8.1.3, pp. 385 to 413 (asset inspections) Section 8.1.4, pp. 414 to 432 (equipment maintenance and repair) Section 8.1.5, pp. 433 to 440 (asset management and inspection enterprise systems) Section 8.1.6, pp. 441 to 445 (quality assurance / quality control) Section 8.1.7, pp. 446 to 461 (open work orders) Section 8.1.9.1, pp. 478 to 481 (workforce planning – asset inspections)
11	Protocols for the de-energization of the electrical corporation's transmission infrastructure, for instance, when the de-energization may impact customers who, or entities that, are dependent upon the infrastructure. The protocols shall comply with any order of the commission regarding de-energization events.	Section 9.2, pp. 766 to 783 (protocols on PSPS) Section 9.2.1, pp. 766 to 775 (protocols on PSPS – risk thresholds) Section 9.2.2, pp. 775 to 788 (protocols on PSPS – method used to compare and evaluate the relative consequence of PSPS and wildfires) Section 9.2.3, pp. 779 to 781 (protocols on PSPS – outline of tactical and strategic decision-making protocol)

TABLE 3-1:
STATUTORY REQUIREMENTS CHECKLIST
(CONTINUED)

Pub. Util. Code Section 8386 (c)	Description	WMP Section and Page Number
		Section 9.2.4, pp. 781 to 783 (protocols for mitigating the public safety impacts of PSPS) Section 9.3, p. 783 (communication strategy for PSPS) Section 9.5, p. 784 (planning and allocation of resources for service restoration due to PSPS)
12	A list that identifies, describes, and prioritizes all wildfire risks, and drivers for those risks, throughout the electrical corporation's service territory, including all relevant wildfire risk and risk mitigation information that is part of the Safety Model and Assessment Proceeding and the Risk Assessment and Mitigation Phase (RAMP) filings.	Section 4.4, pp. 70 to 74 (risk informed framework) Section 6, pp. 133 to 222 (risk methodology and assessment) Section 7, pp. 224 to 316 (mitigation selection process) Section 11, pp. 798 to 806 (corrective action program – prevent recurrence of risk events) Appendix D, pp. 856 to 858 (ACI PG&E-22-01 prioritized list of wildfire risks and drivers) Appendix D, pp. 859 to 860 (ACI PG&E-22-02 collaboration and research in best practices in integrating climate change impacts and wildfire risk and consequence modeling)
13	A description of how the plan accounts for the wildfire risk identified in the electrical corporation's RAMP filing.	Section 6.2.2, pp. 158 to 174 (risk and risk components calculation) Section 6.2.3, pp. 175 to 180 (key assumptions and limitations) Section 6.7, pp. 213 to 222 (risk assessment improvement plan) Section 7, pp. 224 to 316 (mitigation selection process)
14	A description of the actions the electrical corporation will take to ensure its system will achieve the highest level of safety, reliability, and resiliency, and to ensure that its system is prepared for a major event, including hardening and modernizing its infrastructure with improved engineering, system design, standards, equipment, and facilities, such as undergrounding, insulation of distribution wires, and pole replacement.	Section 8.1.1, pp. 318 to 336 (grid operations and maintenance) Section 8.1.2, pp. 337 to 384 (grid design and system hardening) Section 8.4, pp. 621 to 716 (emergency preparedness) Appendix D, pp. 897 to 904 (ACI PG&E-22-11 covered conductor effectiveness and lessons learned) Appendix D, pp. 905 to 906 (ACI PG&E-22-12 covered conducted inspection and maintenance)

TABLE 3-1:
STATUTORY REQUIREMENTS CHECKLIST
(CONTINUED)

Pub. Util. Code Section 8386 (c)	Description	WMP Section and Page Number
		Appendix D, p. 907 (ACI PG&E-22-13 new technologies evaluation and implementation) Appendix D, pp. 911 to 912 (ACI PG&E-22-16 progress and updates on undergrounding and risk prioritization)
15	A description of where and how the electrical corporation considered undergrounding electrical distribution lines within those areas of its service territory identified to have the highest wildfire risk in a CPUC fire threat map.	Section 8.1.2.2, pp. 342 to 349 (undergrounding of electric lines and/or equipment) Appendix D, pp. 911 to 912 (ACI PG&E-22-16 progress and updates on undergrounding and risk prioritization)
16	A showing that the electrical corporation has an adequately sized and trained workforce to promptly restore service after a major event, taking into account employees of other utilities pursuant to mutual aid agreements and employees of entities that have entered into contracts with the electrical corporation.	Section 8.1.8.3, pp. 474 to 477 (personnel work procedures and training in conditions of elevated fire risk) Section 8.1.9.1, pp. 478 to 481 (workforce planning – asset inspections) Section 8.1.9.2, pp. 482 to 488 (workforce planning – grid hardening) Section 8.1.9.3, pp. 489 to 490 (workforce planning – risk event inspection) Section 8.2.7.1, pp. 559 to 563 (workforce planning – vegetation inspections) Section 8.2.7.2, p. 564 (workforce planning – vegetation management projects) Section 8.4.2.2.1, pp. 648 to 660 (personnel qualifications) Section 8.4.2.2.2, pp. 665 to 666 (personnel training) Section 8.4.2.2.3, pp. 671 to 672 (external contractor training) Section 8.4.3.3, pp. 690 to 691 (mutual aid agreements) Section 9.4, p. 784 (key personnel, qualifications, and training for PSPS) Appendix D, p. 914 (ACI PG&E-22-18 retainment of inspections and internal workforce development)
17	Identification of any geographic area in the electrical corporation's service territory that is a higher wildfire threat than is currently identified in a Commission fire threat map, and where the Commission must consider expanding the High Fire Threat District	Section 5.4.3.1, pp. 118 to 121 (individuals at risk from wildfire) Section 5.4.3.2, pp. 122 to 123 (social vulnerability and exposure to electrical corporation wildfire risk)

TABLE 3-1:
STATUTORY REQUIREMENTS CHECKLIST
(CONTINUED)

Pub. Util. Code Section 8386 (c)	Description	WMP Section and Page Number
	based on new information or changes in the environment.	Section 5.4.3.3, pp. 124 to 125 (sub-divisions with limited egress or no secondary egress) Section 5.4.4, pp. 126 to 127 (critical facilities and infrastructure at risk from wildfire) Section 6.4.1.2, pp. 193 to 194 (proposed updates to the HFTD)
18	A methodology for identifying and presenting enterprise-wide safety risk and wildfire-related risk that is consistent with the methodology used by other electrical corporations unless the Commission determines otherwise.	Section 6, pp. 133 to 222 (risk methodology and assessment) Section 7.2.2, pp. 297 to 313 (anticipated risk reduction) Section 7.2.2.1, pp. 297 to 298 (projected overall risk reduction) Section 7.2.2.2, pp. 299 to 305 (risk impact of mitigation initiatives) Section 7.2.2.3, pp. 306 to 313 (projected risk reduction on highest-risk circuits over 3-year WMP cycle) Section 8.1.2.10, pp. 373 to 378 (other grid topology improvements to minimize risk of ignitions) Appendix D, pp. 856 to 858 (ACI PG&E-22-01 prioritized list of wildfire risks and drivers) Appendix D, pp. 859 to 860 (ACI PG&E-22-02 collaboration and research in best practices in integrating climate change impacts and wildfire risk and consequence modeling) Appendix D, pp. 859 to 860 (ACI PG&E-22-07 applying modeling lessons learned from third party review) Appendix D, pp. 886 to 893 (ACI PG&E-22-09 evaluation of model reprioritization and fire rebuild in high-risk areas)
19	A description of how the plan is consistent with the electrical corporation's disaster and emergency preparedness plan prepared pursuant to Section 768.6, including plans to restore service and community outreach.	Section 8.4, pp. 621 to 716 (emergency preparedness)
20	A statement of how the electrical corporation will restore service after a wildfire.	Section 8.4.2, pp. 635 to 682 (emergency preparedness plan)

TABLE 3-1:
STATUTORY REQUIREMENTS CHECKLIST
(CONTINUED)

Pub. Util. Code Section 8386 (c)	Description	WMP Section and Page Number
		Section 8.4.2.1, pp. 636 to 647 (overview of wildfire and PSPS emergency preparedness) Section 8.4.2.2, pp. 648 to 666 (key personnel, qualifications, and training) Section 8.4.3.1, pp. 683 to 685 (emergency planning)
21	Protocols for compliance with requirements adopted by the Commission regarding activities to support customers during and after a wildfire, 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, access to electrical corporation representatives, and emergency communications.	Section 8.4.6, pp. 711 to 716 (customer support in wildfire and PSPS emergencies) Section 8.5.2, pp. 729 to 736 (public outreach and education awareness program) Section 8.5.3, pp. 737 to 743 (engagement with access and functional needs population)
22	A description of the processes and procedures the electrical corporation will use to do the following: Monitor and audit the implementation of the plan. Identify any deficiencies in the plan or the plan's implementation and correct those deficiencies. Monitor and audit the effectiveness of electrical line and equipment inspections, including inspections performed by contractors, carried out under the plan and other applicable statutes and Commission rules.	Section 8.2.5, pp. 549 to 555 (quality assurance and quality control) Section 8.2.5.1, pp. 551 to 552 (quality assurance) Section 8.2.5.2, pp. 553 to 555 (quality control) Section 10, pp. 786 to 796 (lesson learned) Section 11, pp. 798 to 806 (corrective action) Appendix D, pp. 866 to 868 (ACI PG&E-22-07 applying modeling lessons learned from third party review) Appendix D, pp. 915 to 916 (ACI PG&E-22-19 benchmarking with other utilities on inspector qualifications)

PACIFIC GAS AND ELECTRIC COMPANY

2023-2025 WILDFIRE MITIGATION PLAN

SECTION 4

OVERVIEW OF WMP

4. Overview of WMP

4.1 Primary Goal

Each electrical corporation must state the primary goal of its Wildfire Mitigation Plan (WMP). At a minimum, the electrical corporation must affirm its compliance with California Public Utilities Code (Pub. Util. Code) Section 8386(a):

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.

In accordance with California Pub. Util. Code Section 8386(a), Pacific Gas and Electric Company (PG&E) will construct, maintain, and operate our electrical lines and equipment in a manner that will minimize the risk of catastrophic wildfire posed by those electrical lines and equipment. We will thoroughly assess our wildfire risk, develop a comprehensive strategy to reduce ignitions, and implement mitigations designed to minimize the likelihood of catastrophic wildfires to keep our customers and communities safe, ensure the reliability of the electric system, and limit disruption to customers from our wildfire mitigation efforts.

4.2 Plan Objectives

In this section, the electrical corporation must summarize its plan objectives over the 2023-2025 WMP cycle. Plan objectives are determined by the portfolio of mitigation initiatives proposed in the WMP.

PG&E's objectives over the 2023-2025 WMP cycle are to continue to reduce ignition risk via operational mitigations and long-term resilience work, while simultaneously minimizing customer impacts associated with these activities. We have developed a balanced portfolio of mitigations centered on Comprehensive Monitoring and Data Collection, Operational Mitigations, and System Resilience that work together to reduce wildfire risk and strengthen the resiliency of our electric distribution and transmission systems.

The Comprehensive Monitoring and Data Collection mitigations include programs such as inspections and Quality Assurance (QA). Our objectives in this area include plans to:

- Fill asset inventory data gaps; and
- Evaluate implementing a best practices control process.

These activities will help us gain insight into the current state of our electrical system and help us proactively identify and address issues to reduce ignition risk.

Our Operational Mitigations include programs such as Enhanced Powerline Safety Settings (EPSS) and Focused Tree Inspections. Objectives in this area include plans to:

- Update our EPSS reliability study; and
- Through our Focused Tree Inspection program, identify the Areas of Concern (AOC) primarily focused on High Fire Risk Areas (HFRA) and stand up a pilot program (starting in Q2 2023) in at least one AOC.

This work will help us manage current risk on the system while we implement longer-term improvements to permanently reduce risk.

Our System Resilience mitigations include our 10k undergrounding and system hardening programs. Objectives in these areas include:

- Updating the covered conductor effectiveness calculation for consideration in future system hardening work plans.

These programs are designed to reduce risk in the High Fire Threat Districts (HFTD)/HFRAs by changing how our electric systems are constructed and operated.

We describe our portfolio of mitigations to address wildfire risk in Section 8 of this plan.

Along with the mitigation programs that address risk drivers, we are also focused on minimizing impacts to customers from EPSS and Public Safety Power Shutoff (PSPS). Additional details regarding the EPSS Program can be found in Section 8.1.8. We discuss our PSPS Program in Section 9. By addressing key risk drivers through our Operational Mitigations and System Resilience initiatives, and continually improving our situational awareness capabilities, we are working to minimize customer impacts from EPSS and PSPS.

4.3 Proposed Expenditures

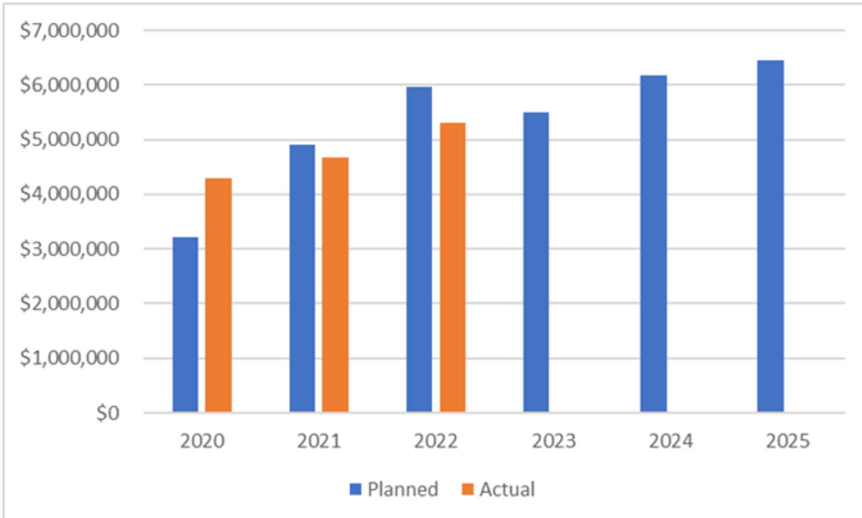
Each electrical corporation must summarize its projected expenditures in thousands of U.S. dollars per year for the next 3-year WMP cycle, as well as the planned and actual expenditures from the previous 3-year WMP cycle (e.g., 2020-2022), in both tabular and graph form.

Table 4-1 summarizes the projected costs (in thousands of dollars) per year over the next 3-year WMP cycle, as well as the planned and actual expenditures from the previous 3-year WMP cycle.

TABLE 4-1:
SUMMARY OF WMP EXPENDITURES
(THOUSANDS OF DOLLARS)

	Spend (Thousands $USD)		
Year	**Planned (2020-2022 in Prior WMP Views)**	**Actual (in 2023 WMP View)**	**Change**
2020	$3,224,295	$4,287,104	$(1,062,809)
2021	$4,898,624	$4,673,631	$244,993
2022	$5,963,795	$5,310,302	$653,493
2023	$5,499,540	N/A	N/A
2024	$6,173,839	N/A	N/A
2025	$6,453,606	N/A	N/A

**FIGURE PG&E-4.3-1:
SUMMARY OF WMP EXPENDITURES
(THOUSANDS OF DOLLARS)**



- Information regarding 2020, 2021, and 2022 “Planned” spends are from prior WMPs, which are based on prior WMP initiatives’ mapping and cost assumptions. As the WMP continues to evolve, the cost mapping is updated to align with the 2023 WMP narrative. This will result in differences from the 2020, 2021, and 2022 “Actual” which is based on the current 2023 WMP view. Changes on the 2022 numbers are mainly driven by lower unit costs in System Hardening, lower VM costs than planned, and other mapping updates to tie to the 2023 WMP narrative.

- Table 4-1 spans multiple cost recovery mechanisms including the General Rate Case, Transmission Owner rate case at the Federal Energy Regulatory Commission, Fire Risk Mitigation Memorandum Account, Wildfire Mitigation Plan Memorandum Account, Microgrid Memorandum Account, Microgrids Balancing Account, Electric Program Investment Charge, and Wildfire Mitigation Balancing Account. Some of these costs have already been approved for inclusion in customer rates and some of these costs are still pending review or approval through cost recovery proceedings.

- While the primary work performed for wildfire risk mitigation is in HFTD areas, some work and financial costs associated with Non-HFTD or rest of territory have been included in the WMP expenditure information.

- 2023 “Planned” costs are PG&E’s best estimate for the proposed programs at this time and based on PG&E’s approved Budget. Further changes to 2023 Budget and work plans are possible and actual costs may vary substantially from these plans depending on actual work completion, conditions, and requirements.

- The 2023 Plan, for the most part, is tied to the approved PG&E budget, which could include additional dollars for more work or units.

- 2024 and 2025 “Plans” are current forecasts and not official approved budgets. 2024 and 2025 forecasts are updated for certain activities to align with workplan commitments (e.g., undergrounding). However, for many activities 2024 and 2025 forecasts are based on the 2023 plan with a simple 3 percent escalation.

4.4 Risk-Informed Framework

The electrical corporation must adopt a risk-informed approach to developing its WMP. The purposes of adopting this approach are as follows:

- *To develop a WMP that achieves an optimal level of life safety, property protection, and environmental protection, while also being in balance with other performance objectives (e.g., reliability and affordability);*
- *To integrate risk modeling outcomes with a range of other performance objectives, methods, and subject matter expertise to inform decision-making processes and the spatiotemporal prioritization of mitigations;*
- *To target mitigation efforts that prioritize the highest-risk equipment, wildfire environmental settings, and assets-at-risk (e.g., people, communities, critical infrastructure), while still satisfying other performance objectives defined by the California Public Utilities Commission (CPUC) (e.g., reliability and affordability); and*
- *To provide a decision-making process that is clear and transparent to internal and external stakeholders, including clear evaluation criteria and visual aids (such as flow charts or decision trees).*

The risk-informed approach adopted by the electrical corporation must, at a minimum, incorporate several key components, described below. In addition, the evaluation and management of risk must include consideration of a broad range of performance objectives (e.g., life safety, property protection, reduction of social vulnerability, reliability, resiliency, affordability, health, environmental protection, public perception, etc.), integrate cross-disciplinary expertise, and engage various stakeholder groups as part of the decision-making process.

Table 4-2 below lists the components that make-up PG&E's risk-informed approach to developing our WMP. The table includes a brief summary of each component and provides a reference to the section in the WMP where PG&E describes the component in more detail.

TABLE 4-2:
THE COMPONENTS OF PG&E'S RISK-INFORMED APPROACH

Line No.	Risk-Informed Approach Component	Brief Description of Risk-Informed Approach	Reference to WMP Section for Additional Detail
1	Goals and Objectives	In accordance with California Pub. Util. Code Section 8386(a), PG&E will construct, maintain, and operate our electrical lines and equipment in a manner that will minimize the risk of catastrophic wildfire posed by those electrical lines and equipment. PG&E will thoroughly assess our wildfire risk, develop a comprehensive strategy to reduce ignitions, and implement mitigations designed to minimize the likelihood of catastrophic wildfires to keep our customers and communities safe, ensure the reliability of the electric system, and limit disruption to customers. PG&E sets forth our specific risk reduction targets and objectives in Section 8.	Section 4.2
2	Scope of Application (PG&E's Service Territory)	PG&E's service territory covers more than 71,000-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. More than 50 percent of our territory sits in HFRA and/or in the HFTD. Our service territory is shaped by macro and micro-climates with diverse fire ecology regimes. Managing wildfire risk in these diverse regimes requires a wide variety of risk-informed system monitoring and mitigation efforts.	Section 5.0 through Section 5.4
3	Hazard Identification	PG&E's risk analysis framework informs our risk mitigation strategy by quantifying the existing risk and the risk reduction that occurs after we implement our mitigations. We develop predictive analytical models to quantify the probability and impact (consequence) associated with each risk driver. The components of the framework are dynam–c – input data and modeling assumptions and tools are adjusted as we mature and improve our predicitive risk models.	Section 6.2.1

TABLE 4-2:
THE COMPONENTS OF PG&E'S RISK-INFORMED APPROACH
(CONTINUED)

Line No.	Risk-Informed Approach Component	Brief Description of Risk-Informed Approach	Reference to WMP Section for Additional Detail
4	Risk Scenario Identification	PG&E's risk modeling framework aims to account for all scenarios in a single predictive model that is represented by the historical data sets used in model development. As part of our dedication to continuously improve risk modeling we will seek methods to appropriately account for extreme scenarios in the future.	Section 6.3
5	Risk Presentation	PG&E presents three maps showing our top risk in the HFRA: Wildfire Distribution Risk Model Outputs; Wildfire Transmission Risk Model Outputs; and PSPS Risk Map.	Section 6.4
6	Risk Analysis (Likelihood and Consequences)	PG&E describes our methods and provides schematics showing how we calculate the likelihood and consequences of a risk event.	Section 6.2.2
7	Risk Evaluation	PG&E's approach to risk evaluation relies on a mitigation strategy that is risk informed using wildfire risk models, executable, and aligned to available resources. We accomplish this by engaging key-stakeholders and following a defined decision-making process. PG&E's Wildfire mitigation strategy centers around using our knowledge of key risk drivers and historic risk event data to develop and socialize Transmission and Distribution wildfire risk models. We use our risk models to develop risk buydown curves for prioritizing risk reduction and to develop a balanced portfolio mitigation initiatives.	Section 7
8	Risk Mitigation and Management	PG&E's approach to managing and mitigating risk is centered on our balanced portfolio of Operational Mitigations and System Resilience Mitigations. We rely on Operational Mitigations to manage system risk, reduce customer impacts due to system outages, and improve system reliability on an on-going basis. We implement System Resilience mitigations to change how we operate and maintain the grid and provide more permanent risk reduction. Our objectives, targets, and performance metrics are designed to improve performance and measure progress towards meeting our goals. We build in additional layers of defense through Quality Control and QA programs.	Section 8

Along with the eight elements in Table 4-2 that make-up our risk-informed approach to developing the WMP, we also integrate cross-functional expertise, consider a broad range of performance objectives, and engage various stakeholders for input.

Cross-Functional Internal and External Stakeholder Engagement

- We rely on the expertise from internal cross-functional teams including our Wildfire Risk Governance Steering Committee, which is comprised of senior leaders from Risk Management and Electric Operations, as well as team members from Wildfire Risk Management, Asset Strategy, Engineering and Standards, Ignitions Investigations, Vegetation Management, Investment Planning, Major Projects, Electric Operations, and Asset Knowledge and Management.

- We collaborate with external stakeholders such as the California Department of Forestry and Fire Protection, the Office of Energy Infrastructure Safety, the CPUC, environmental agencies such as California Fish and Game and Regional Water Quality Boards, California Independent System Operator, other California investor-owned utilities, California Fire Safe Councils, PG&E customers, Community-Based Organizations (CBO), local communities, and government leaders.

- We interact with our customers though meetings and town-hall type events hosted by our Regional Vice Presidents (VP). The Regional VPs bring customer concerns and input back to our governance committee.

Mitigation Program Performance Objectives and Considerations

- When selecting areas for undergrounding projects and covered conductor installation, we look for locations that will reduce wildfire risk and PSPS customer impacts. In addition, our Public Safety Specialists (PSS) identify locations presenting elevated wildfire risk that may not be identified by the risk models.

- We consider customer and community impacts and cultural considerations when performing undergrounding and other system hardening work and work closely with customers, government agencies, tribes, and regulatory agencies to manage these issues, minimize delays, and optimize efficiency.

- Our Community Microgrid Enablement Program (CMEP) addresses PSPS mitigation and supports energy resilience for our customers and communities. CMEP's objective is to empower communities directly through a combination of technical and financial assistance, as well as through development of the tariffs and agreements necessary to facilitate multi-customer microgrids which helps communities with the technical, financial, legal, and regulatory challenges.

- We will test the feasibility to create a species-specific stress index model for PG&E tree health and mortality. We are working with an external vendor who will deliver system-wide satellite imagery providing dead tree canopy coverage. Historic and periodic future snapshots will allow us to build machine learning capabilities to predict tree health, taking into account static environmental factors and dynamic weather/climate effects.

- Our Integrated Vegetation Management Program for transmission promotes desirable, stable, low-growing plant communities that resist invasion by tall growing tree and brush species, through appropriate, environmentally sound, and cost-effective control methods.

Community Engagement and Support for Wildfire Emergencies and PSPS Events

- PG&E works with key community stakeholders and our public safety partners to address issues related to wildfire preparations, wildfire safety work, and other public safety and preparedness issues that may impact their communities. Along with sharing information with our partners, we use these interactions to gather feedback so that we can better serve our communities.

- We have assigned more than 50 dedicated representatives within our Federal Affairs, State Government Relations, Local Public Affairs, PSS, and Tribal Relations departments who are responsible for identifying and maintaining relationships within federal, state, local, and tribal agencies. Our dedicated representatives are divided into regions to best serve stakeholders at a local level.

- In the event of wildfire emergencies and PSPS events, PG&E provides support for low-income customers, including freezing California Alternate Rates for Energy eligibility standards, increasing the assistance cap for the emergency assistance program, and modifying qualification requirements for the Energy Savings Assistance Program.

- Community outreach and public awareness are key components of our emergency planning and preparedness efforts to ensure customers and communities are informed and adequately prepared prior to a wildfire or wildfire safety outage like PSPS or EPSS. We conduct outreach in advance of, during, and after peak wildfire season to ensure customers and stakeholders understand the programs, their wildfire safety benefits, the potential impacts, and support that is available for customers and communities.

- Prior to peak wildfire season, we execute a wildfire safety and PSPS preparedness community outreach strategy, using lessons learned and feedback received from customers and stakeholders. Further, PG&E conducts community outreach to educate agencies, customers, and property owners on aspects of our wildfire mitigation practices. Key community groups we interact with include customers with Access or Functional Needs, residential and unassigned Small Medium Business customers, property owners and property managers, critical facilities, such as water agencies, communications providers, hospitals, and CBOs.

PACIFIC GAS AND ELECTRIC COMPANY

2023-2025 WILDFIRE MITIGATION PLAN

SECTION 5

OVERVIEW OF THE SERVICE TERRITORY

5 Overview of the Service Territory

5.1 Service Territory

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

- *Area served (in square miles (sq. mi)); and*
- *Number of customers served.*

The electrical corporation must provide a geospatial map that shows its service territory (polygons) and distribution of customers served (raster or polygons). This map should appear in the main body of the report.

Pacific Gas and Electric Company's (PG&E) service territory covers more than 71,000-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 California counties, including northern Santa Barbara County.

Our service territory consists of approximately 44 percent High Fire Thread District (HFTD) Tier 2 and 8 percent HFTD Tier 3. More information about HFTD in PG&E's service territory is provided in Section 5.3.3.

Additionally, the topographic elevation ranges throughout our service territory are highly variable, including Coast Ranges, Great Valley, Sierra Nevada, Mojave Desert, and Modoc Plateau/Cascade Range. More information about topography conditions in PG&E's service territory is provided in Section 5.3.5.

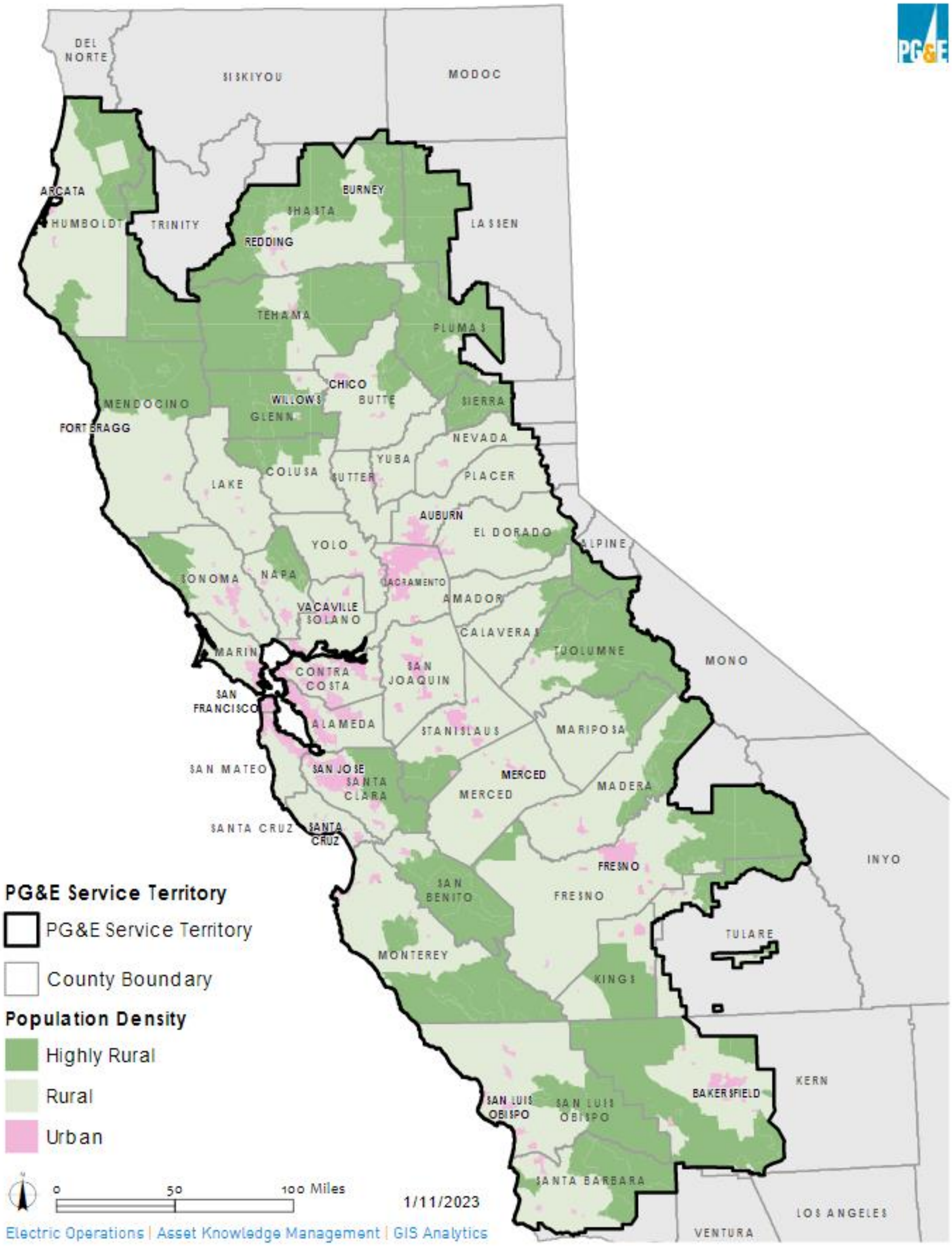
Table 5-1 below shows the total area served in square miles and the total number of electric customers served.

TABLE 5-1:
SERVICE TERRITORY HIGH LEVEL STATISTICS

Characteristic	Measurements
Area Served (sq. mi.)	71,732
Number of Electric Customers Served	5,726,039

Figure PG&E-5.1-1 below shows the square miles in our service territory that correspond to the population density for highly rural, rural, and urban customers. Please refer to Appendix A for definitions of highly rural, rural, and urban customers.

FIGURE PG&E-5.1-1:
POPULATION DENSITY MAP OF HIGHLY RURAL, RURAL, AND URBAN CUSTOMERS



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

5.2 Electrical Infrastructure

The electrical corporation must provide a high-level description of its infrastructure, including all power generation facilities, transmission lines and associated equipment, distribution lines and associated equipment, substations, and any other major equipment.

PG&E's electric infrastructure consists of more than 80,000 miles of overhead distribution lines, 18,000 miles of overhead transmission lines, 27,000 miles of underground distribution lines, 180 miles of underground transmission lines and 990 substations.

Table 5-2 below shows total electric equipment by type and total count in the HFTD (which consists of HFTD Tier 2 and 3) and non-HFTD areas. Most of the total count is obtained from our two databases, generated using Electric Transmission Geographic Information System (ETGIS) and Electric Distribution Geographic Information System (EDGIS) databases. The table information is supplemented by information from other databases and Subject Matter Expert-provided information from other data sources.

TABLE 5-2:
ELECTRICAL INFRASTRUCTURE

Type of Equipment	HFTD	Non-HFTD	Total
Overhead distribution lines (circuit miles)	24,911	55,299	80,210
Overhead transmission lines (circuit miles)	5,506	12,605	18,111
Underground distribution lines (circuit miles)	2,935	24,914	27,850
Underground transmission lines (circuit miles)	12	170	182
Critical Facility	10,917	74,083	85,000
Residential Customer	479,764	4,511,794	4,991,558
Commercial Customer	55,047	670,070	725,117
Access and Functional Needs (AFN) Customers	121,642	1,451,000	1,572,642
Substations	252	740	992
Weather Stations	1,118	314	1,433

5.3 Environmental Settings

5.3.1 Fire Ecology

The electrical corporation must provide a brief narrative describing the fire ecology or ecologies across its service territory. This includes a brief description of how ecological features, such as the following, influence the propensity of the electrical corporation's service territory to experience wildfires: generalized climate and weather conditions, ecological regions and associated vegetation types, and Fire Return Intervals (FRI).

The electrical corporation must provide tabulated statistics of t the vegetative coverage across its service territory. The tabulated data must include a breakdown of the vegetation types, total acres per type, and percentage of service territory per type. The electrical corporation must identify the vegetative database used to characterize the vegetation (e.g., Classification and Assessment with Landsat of Visible Ecological Groupings (CALVEG)).

Like most other regions influenced by a Mediterranean-type climate, fire has been a key ecological process and evolutionary driver in California ecosystems for millennia.[4,5] Today, California ecosystems exhibit a wide array of ecological and evolutionary relationships with fire,[6] and PG&E's service territory, which covers nearly half of California, encompasses much of that diversity.

Ecological and evolutionary relationships with fire are best understood using the concept of fire regimes,[7] which describe spatial, temporal, and magnitudinal fire patterns that characterize different ecosystems. The following discussion of the fire ecology in PG&E's service territory focuses on a single aspect of fire regime—how often fire occurs. This aspect of fire regime is commonly quantified in one of two ways.[8]

- First, it can be quantified using FRI (synonymous with fire interval, fire free interval, and inter-fire interval), which refers to the elapsed time between consecutive fires that burn a given point on the landscape (e.g., 10 years/fire).
- Second, it can be quantified using fire frequency, which refers to the number of fires per unit of time that burn a given point on the landscape (e.g., 0.1 fires/year), and is simply the inverse of FRI (10 years/fire = 0.1 fires/year).

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4 The citations in the body of this document refer only to the name of the author. The complete list of documents referenced in this discussion is provided in Table PG&E-5.3.1-1 in Appendix F. Many of the documents referenced are subscription-based and are not publicly available.

5 Anderson (2006); Beaty and Taylor (2009); Swetnam et al. (2009).

6 Sugihara et al. (2006).

7 Heinselman (1981).

8 Romme (1980).

This discussion uses the metric FRI.

Since fire regime is an integral component of plant communities, mapping of existing vegetation types greatly facilitates the description of variation in fire regime characteristics such as FRI. Existing vegetation was mapped for PG&E's service territory primarily with the United States Forest Service's (USFS) Existing Vegetation Geodatabase (EVEG),[9] which uses the Classification and Assessment with Landsat of Visible Ecological Groupings (CALVEG) classification[10] (Table 5-3). Three areas of PG&E's service territory near the central California coast (2,290,474 acres, approximately 5 percent of PG&E service territory) have not been mapped by EVEG, so existing vegetation in these areas was identified using LANDFIRE's Existing Vegetation Type data,[11] and then cross-walked to CALVEG vegetation types. The CALVEG vegetation types were then consolidated into Pre-Euro-American Settlement Fire Regime (PFR) groups based on similarity in species composition, vegetation structure, and PFR attributes, following Van de Water and Safford[12] and Safford and Van de Water[13] (Table 5-3, Figure PG&E-5.3.1-1).

For each PFR in PG&E's service territory, the mean, minimum, and maximum estimates of pre-Euro-American settlement FRIs were obtained from Van de Water and Safford (2011) (Figure PG&E-5.3.1-2). Estimates of current FRI were calculated for each PFR using data from the USFS's California Fire Return Interval Departure (FRID) geodatabase (Safford and Van de Water 2014, available at: <https://www.fs.usda.gov/main/r5/landmanagement/gis)>, accessed January 26, 2023. Specifically, current FRI was estimated for a given PFR by taking an area-weighted average of the FRIs reported by the FRID geodatabase across all areas mapped to that PFR.

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9 Available at: <https://data.fs.usda.gov/geodata/edw/datasets.php> accessed January 26, 2023.

10 Franklin et al. (2000). See, <https://www.fs.usda.gov/detail/r5/landmanagement/resourcemanagement/?cid=stelprdb5347192>, accessed January 26, 2023.

11 EVT, Rollins et al. (2009), available at: <https://www.landfire.gov/getdata.php>, accessed January 26, 2023.

12 Van de Water and Safford (2011).

13 Safford and Van de Water (2014).

TABLE 5-3:
EXISTING VEGETATION TYPES IN THE SERVICE TERRITORY

Vegetation Type	Pre-Euro-American Fire Regime Group	Acres	Percentage of Service Territory
Agricultural Nurseries (General)	No PFR	125	0.0003%
Agricultural Ponds or Water Feature	No PFR	929	0.0020%
Agriculture	No PFR	1,109,209	2.4161%
Alkaline Flats	No PFR	37	0.0001%
Alkaline Mixed Grasses and Forbs	Insufficient Fire Regime Information	8,429	0.0184%
Alkaline Mixed Scrub	Desert mixed shrub	1,053	0.0023%
Alpine Mixed Grasses and Forbs	Insufficient Fire Regime Information	29,401	0.0640%
Alpine Mixed Scrub	Subalpine forest	2,270	0.0049%
Annual Grasses and Forbs	Grasses and Forbs	8,788,497	19.1436%
Arrowweed	Insufficient Fire Regime Information	434	0.0009%
Aspen (Shrub)	Aspen	1,479	0.0032%
Baccharis (Riparian)	Insufficient Fire Regime Information	351	0.0008%
Barrens	No PFR	834,226	1.8172%
Bays or Estuaries	No PFR	6,265	0.0136%
Beach Pine	Shore pine	503	0.0011%
Beach Sand	No PFR	3,085	0.0067%
Big Basin Sagebrush	Big sagebrush	26	0.0001%
Big Sagebrush	Big sagebrush	154,640	0.3368%
Big Tree	Moist mixed conifer	561	0.0012%
Bigcone Douglas-Fir	Bigcone Douglas-fir	3,739	0.0081%
Bigleaf Maple	Mixed evergreen	2,257	0.0049%
Birchleaf Mountain Mahogany	Chaparral and serotinous conifers	5,511	0.0120%
Bishop Pine	Chaparral and serotinous conifers	25,460	0.0555%
Bitterbrush	Big sagebrush	19	<0.0001%
Bitterbrush – Sagebrush	Big sagebrush	63	0.0001%
Black Cottonwood	Insufficient Fire Regime Information	1,532	0.0033%
Black Oak	Yellow pine	392,849	0.8557%
Black Walnut	Mixed evergreen	9	<0.0001%
Bladderpod	Desert mixed shrub	1,042	0.0023%
Blue Oak	Oak woodland	2,607,032	5.6788%
Blueblossom	Chaparral and serotinous conifers	12,373	0.0270%

TABLE 5-3:
EXISTING VEGETATION TYPES IN THE SERVICE TERRITORY
(CONTINUED)

Vegetation Type	Pre-Euro-American Fire Regime Group	Acres	Percentage of Service Territory
Brewer Oak	Oak woodland	6,462	0.0141%
Brewer Spruce	Fire sensitive spruce or fir	2	<0.0001%
Buckwheat	Coastal sage scrub	74,164	0.1615%
Bush Chinquapin	Montane chaparral	1,705	0.0037%
California Bay	Mixed evergreen	77,937	0.1698%
California Buckeye	Mixed evergreen	2,671	0.0058%
California Juniper	California juniper	19,078	0.0416%
California Sagebrush	Coastal sage scrub	645,739	1.4066%
California Sycamore	Insufficient Fire Regime Information	15,861	0.0345%
California Yucca	Chaparral and serotinous conifers	334	0.0007%
Canyon Live Oak	Mixed evergreen	561,433	1.2229%
Ceanothus Chaparral	Chaparral and serotinous conifers	58,341	0.1271%
Chamise	Chaparral and serotinous conifers	641,792	1.3980%
Coast Live Oak	Mixed evergreen	850,999	1.8537%
Coastal Bluff Scrub	Coastal sage scrub	125	0.0003%
Coastal Lupine	Insufficient Fire Regime Information	6,516	0.0142%
Coastal Mixed Hardwood	Mixed evergreen	83,103	0.1810%
Conifer Agriculture	No PFR	59	0.0001%
Cottonwood – Alder	Insufficient Fire Regime Information	1,264	0.0028%
Coulter Pine	Chaparral and serotinous conifers	32,758	0.0714%
Coyote Brush	Chaparral and serotinous conifers	74,937	0.1632%
Curl-leaf Mountain Mahogany	Curl-leaf mountain mahogany	10,799	0.0235%
Deerbrush	Montane chaparral	4,927	0.0107%
Developed Water Features	No PFR	1,590	0.0035%
Douglas-Fir – Grand Fir	Coastal fir	18,157	0.0395%
Douglas-Fir – Pine	Moist mixed conifer	955,516	2.0814%
Douglas-Fir – White Fir	Moist mixed conifer	140,508	0.3061%
Dunes	No PFR	13,658	0.0298%
Eastside Pine	Yellow pine	264,329	0.5758%
Encelia Scrub	Coastal sage scrub	113	0.0002%

TABLE 5-3:
EXISTING VEGETATION TYPES IN THE SERVICE TERRITORY
(CONTINUED)

Vegetation Type	Pre-Euro-American Fire Regime Group	Acres	Percentage of Service Territory
Eucalyptus	No PFR	22,958	0.0500%
Exposed Non-Water Features	No PFR	12,779	0.0278%
Flooded Row Crop Agriculture	No PFR	500,874	1.0910%
Foxtail Pine	Subalpine forest	3,136	0.0068%
Fremont Cottonwood	Insufficient Fire Regime Information	12,918	0.0281%
Giant Reed/Pampas Grass	No PFR	269	0.0006%
Grain and Crop Agriculture	No PFR	5,370,511	11.6984%
Grand Fir	Coastal fir	6,554	0.0143%
Gray Pine	Oak woodland	740,079	1.6121%
Great Basin – Mixed Chaparral Transition	Chaparral and serotinous conifers	5,982	0.0130%
Great Basin Mixed Scrub	Big sagebrush	3,000	0.0065%
Great Basin – Desert Mixed Scrub	Desert mixed shrub	1	<0.0001%
Greenleaf Manzanita	Montane chaparral	7,630	0.0166%
Huckleberry Oak	Montane chaparral	61,208	0.1333%
Incense Cedar	Moist mixed conifer	396	0.0009%
Interior Live Oak	Mixed evergreen	559,613	1.2190%
Interior Mixed Hardwood	Mixed evergreen	491,077	1.0697%
Intermittent or Seasonal Lake	No PFR	24,861	0.0542%
Intermittent Stream Channel	No PFR	5,129	0.0112%
Jeffrey Pine	Yellow pine	158,687	0.3457%
Klamath Mixed Conifer	Moist mixed conifer	0	<0.0001%
Knobcone Pine	Chaparral and serotinous conifers	82,278	0.1792%
Limber Pine	Subalpine forest	26	0.0001%
Lodgepole Pine	Lodgepole pine	175,331	0.3819%
Low Sagebrush	Black and Low sagebrush	12,878	0.0281%
Lower Montane Mixed Chaparral	Chaparral and serotinous conifers	1,999,568	4.3556%
Madrone	Mixed evergreen	6,904	0.0150%
Manzanita	Chaparral and serotinous conifers	44,465	0.0969%
McNab Cypress	Chaparral and serotinous conifers	15,460	0.0337%

TABLE 5-3:
EXISTING VEGETATION TYPES IN THE SERVICE TERRITORY
(CONTINUED)

Vegetation Type	Pre-Euro-American Fire Regime Group	Acres	Percentage of Service Territory
Mixed Conifer – Fir	Moist mixed conifer	1,318,749	2.8726%
Mixed Conifer – Pine	Dry mixed conifer	2,222,738	4.8417%
Mixed Conifer with Giant Sequoia	Moist mixed conifer	18,326	0.0399%
Mixed Soft Scrub – Chaparral	Chaparral and serotinous conifers	21,565	0.0470%
Montane Mixed Hardwoods	Mixed evergreen	83,083	0.1810%
Monterey Cypress	Chaparral and serotinous conifers	475	0.0010%
Monterey Pine	Chaparral and serotinous conifers	7,378	0.0161%
Mountain (Thinleaf) Alder	Insufficient Fire Regime Information	7,757	0.0169%
Mountain Hemlock	Subalpine forest	14,449	0.0315%
Mountain Misery	Yellow pine	1,101	0.0024%
Mountain Sagebrush	Big sagebrush	14,175	0.0309%
Mountain Whitethorn	Montane chaparral	6,177	0.0135%
Nissenan Manzanita	Chaparral and serotinous conifers	55	0.0001%
Non-Native/Invasive Forb/Grass	No PFR	2,338	0.0051%
Non-Native/Ornamental Conifer	No PFR	6,456	0.0141%
Non-Native/Ornamental Conifer/Hardwood	No PFR	13,818	0.0301%
Non-Native/Ornamental Grass	No PFR	103,235	0.2249%
Non-Native/Ornamental Hardwood	No PFR	18,731	0.0408%
Non-Native/Ornamental Shrub	No PFR	51,079	0.1113%
North Coastal Scrub	Chaparral and serotinous conifers	9,228	0.0201%
Not Mapped by EVEG	Not Mapped by EVEG	20,017	0.0436%
Ocean	No PFR	477	0.0010%
Orchard Agriculture	No PFR	1,711,995	3.7292%
Oregon White Oak	Oak woodland	459,303	1.0005%
Pacific Douglas-Fir	Mixed evergreen	1,944,996	4.2367%
Perennial Grasses and Forbs	Grasses and Forbs	114,774	0.2500%
Perennial Lakes and Ponds	No PFR	200,768	0.4373%
Pickleweed – Cordgrass	Insufficient Fire Regime Information	71,937	0.1567%

TABLE 5-3:
EXISTING VEGETATION TYPES IN THE SERVICE TERRITORY
(CONTINUED)

Vegetation Type	Pre-Euro-American Fire Regime Group	Acres	Percentage of Service Territory
Pinemat Manzanita	Montane chaparral	2,359	0.0051%
Playas	No PFR	186	0.0004%
Ponderosa Pine	Yellow pine	1,154,576	2.5150%
Ponderosa Pi–e – White Fir	Dry mixed conifer	15,071	0.0328%
Port Orford Cedar	Port Orford cedar	3,815	0.0083%
Pygmy (Fort Bragg) Manzanita	Chaparral and serotinous conifers	278	0.0006%
Pygmy (Gowen) Cypress	Chaparral and serotinous conifers	5,431	0.0118%
Quaking Aspen	Aspen	7,898	0.0172%
Rabbitbrush	Big sagebrush	2,921	0.0064%
Red Alder	Insufficient Fire Regime Information	24,713	0.0538%
Red Fir	Red fir	693,215	1.5100%
Redshank	Chaparral and serotinous conifers	396	0.0009%
Redwood	Redwood	388,492	0.8462%
Redwood – Douglas Fir	Redwood	1,021,154	2.2243%
Reservoirs	No PFR	80,959	0.1763%
Ribarian Mixed Shrub	Insufficient Fire Regime Information	25,267	0.0550%
Riparian Mixed Hardwood	Insufficient Fire Regime Information	79,765	0.1737%
Rivers and Streams	No PFR	136,725	0.2978%
Rothrock Sagebrush	Big sagebrush	30	0.0001%
Sage (Salvia)	Coastal sage scrub	40	0.0001%
Sal–l – California Huckleberry	Mixed evergreen	2,245	0.0049%
Saltbush	Desert mixed shrub	235,365	0.5127%
Santa Lucia Fir	Fire sensitive spruce or fir	341	0.0007%
Sargent Cypress	Chaparral and serotinous conifers	16,151	0.0352%
Scalebroom	Desert mixed shrub	269	0.0006%
Scrub Oak	Chaparral and serotinous conifers	136,697	0.2978%
Shadscale	Desert mixed shrub	7	0.0000%
Shreve Oak	Mixed evergreen	130	0.0003%
Shrub Willow	Insufficient Fire Regime Information	43,183	0.0941%
Silver Sagebrush	Silver sagebrush	58	0.0001%

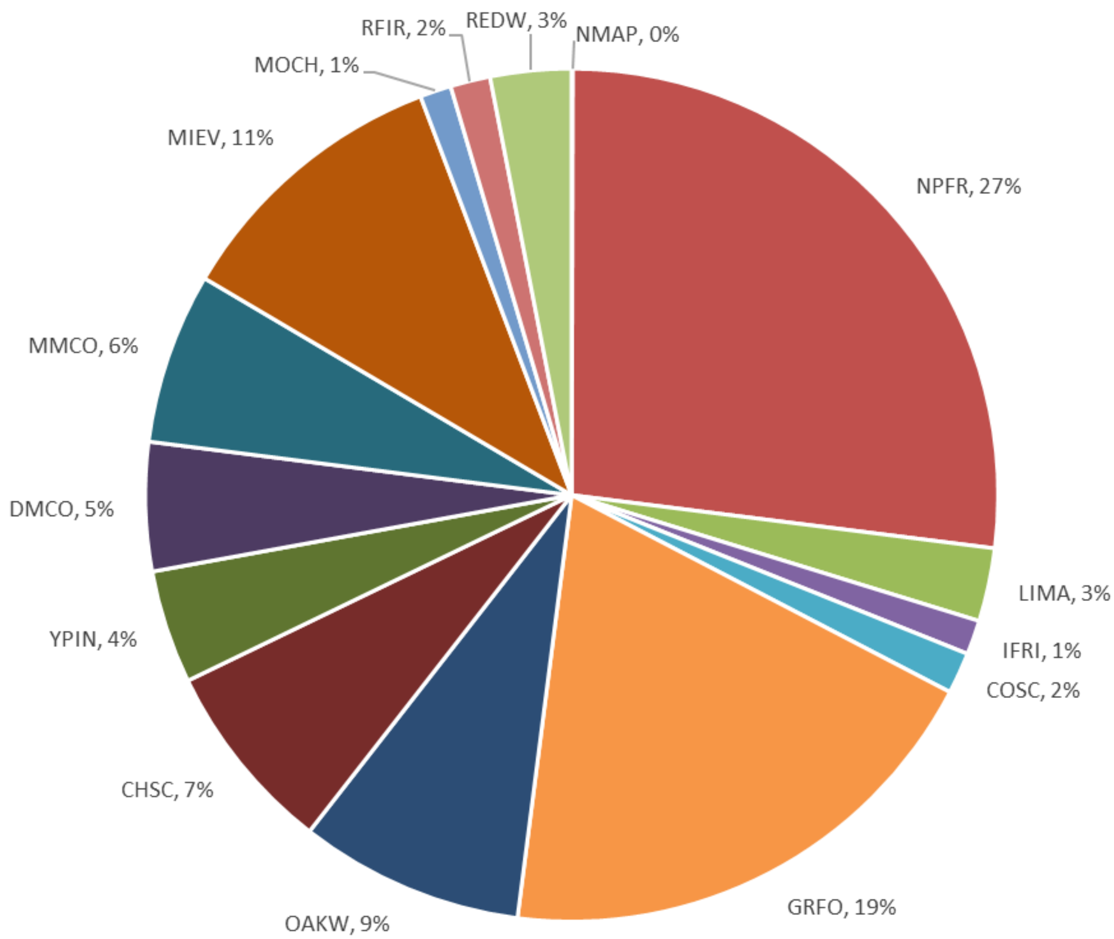
TABLE 5-3:
EXISTING VEGETATION TYPES IN THE SERVICE TERRITORY
(CONTINUED)

Vegetation Type	Pre-Euro-American Fire Regime Group	Acres	Percentage of Service Territory
Singleleaf Pinyon Pine	Pinyon juniper	49,707	0.1083%
Sitka Spruce	Spruce-hemlock	11,106	0.0242%
Sitka Spruce – Grand Fir	Spruce-hemlock	7,880	0.0172%
Sitka Spruce – Redwood	Spruce-hemlock	37,111	0.0808%
Snow/Ice	No PFR	3,012	0.0066%
Snowberry	Big sagebrush	201	0.0004%
Snowbrush	Montane chaparral	355	0.0008%
Subalpine Conifers	Subalpine forest	213,380	0.4648%
Sugar Pine	Moist mixed conifer	46	0.0001%
Sumac Shrub	Chaparral and serotinous conifers	13	<0.0001%
Tamarisk	No PFR	1,129	0.0025%
Tanoak (Madrone)	Mixed evergreen	262,419	0.5716%
Tilled Earth Agriculture	No PFR	34,211	0.0745%
Tree Chinquapin	Mixed evergreen	1,647	0.0036%
Tucker/Muller Scrub Oak	Semi-desert chaparral	50,545	0.1101%
Tule – Cattail	Insufficient Fire Regime Information	156,230	0.3403%
Ultramafic Mixed Conifer	Moist mixed conifer	22,414	0.0488%
Ultramafic Mixed Shrub	Chaparral and serotinous conifers	11,111	0.0242%
Upper Montane Mixed Chaparral	Montane chaparral	425,921	0.9278%
Upper Montane Mixed Shrub	Montane chaparral	35,362	0.0770%
Urban	No PFR	1,639,595	3.5715%
Urban-Related Bare Soil	No PFR	61,536	0.1340%
Valley Oak	Oak woodland	95,023	0.2070%
Vernal Pool	Insufficient Fire Regime Information	123	0.0003%
Vineyard – Shrub Agriculture	No PFR	142,460	0.3103%
Water	No PFR	257,050	0.5599%
Wedgeleaf Ceanothus	Chaparral and serotinous conifers	99,811	0.2174%
Western (Mountain) Juniper	Pinyon juniper	83,805	0.1825%
Western White Pine	Western white pine	43,220	0.0941%

TABLE 5-3:
EXISTING VEGETATION TYPES IN THE SERVICE TERRITORY
(CONTINUED)

Vegetation Type	Pre-Euro-American Fire Regime Group	Acres	Percentage of Service Territory
Wet Meadows (Grass – Sedge – Rush)	Insufficient Fire Regime Information	81,927	0.1785%
White Alder	Insufficient Fire Regime Information	2,623	0.0057%
White Fir	Moist mixed conifer	520,219	1.1332%
Whitebark Pine	Subalpine forest	67,276	0.1465%
Whiteleaf Manzanita	Chaparral and serotinous conifers	38,728	0.0844%
Willow	Insufficient Fire Regime Information	16,723	0.0364%
Willow – Alder	Insufficient Fire Regime Information	9,969	0.0217%
Willow – Aspen	Aspen	105	0.0002%
Winterfat	Big sagebrush	17,037	0.0371%
Yellow Pine – Western Juniper	Yellow pine	1,482	0.0032%
Total		45,908,281	100.0000%

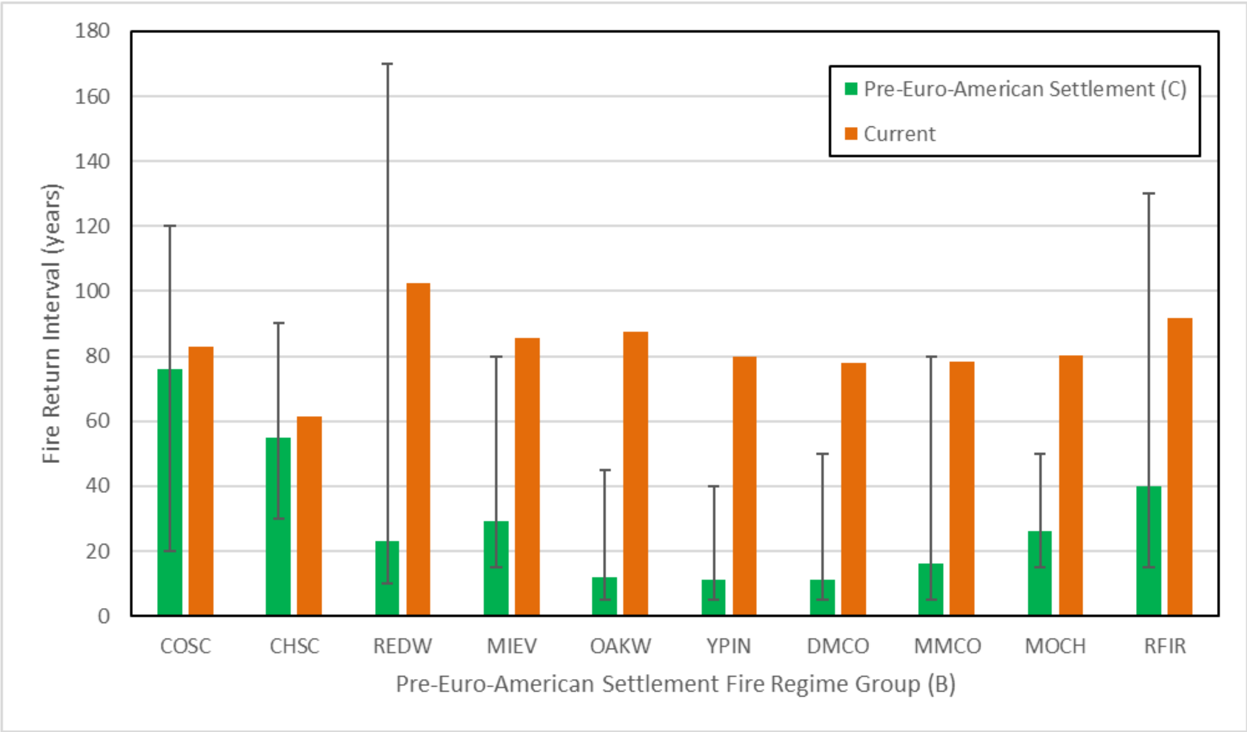
FIGURE PG&E-5.3.1-1:
PROPORTIONS OF PG&E SERVICE TERRITORY OCCUPIED BY EXISTING VEGETATION TYPES, AGGREGATED BY PFR GROUP



Note Pre-Euro-American Settlement Fire Regime (PFR) Group abbreviations:

- NMAP: Not Mapped by EVEG;
- NPFR: No PFR;
- LIMA: Limited Area;
- IFRI: Insufficient Fire Regime Information;
- COSC: Coastal Sage Scrub;
- GRFO: Grasses and Forbs;
- OAKW: Oak Woodland;
- CHSC: Chaparral and Serotinous Conifers;
- YPIN: Yellow Pine;
- DMCO: Dry Mixed Conifer;
- MMCO: Moist Mixed Conifer;
- MIEV: Mixed Evergreen;
- MOCH: Montane Chaparral;
- RFIR: Red Fir; and
- REDW: Redwood.

FIGURE PG&E-5.3.1-2:
FRIS FOR PRE-EURO AMERICAN FIRE REGIME GROUPS (A)



(a) FRIs only shown for those PFR groups: (1) that exhibited PFRs (e.g., excluding water, barrens, agriculture), (2) for which sufficient information exists to confidently quantify pre-Euro American settlement FRIs, and (3) currently occupy 1 percent or more of PG&E service territory.

(b) See Figure PG&E 5.3.1-1 for key to PFR group abbreviation.

(c) Green bars represent the mean of published pre-Euro American settlement (pre-1850) FRI estimates for each PFR group (Van de Water and Safford 2011). Error bars represent minimum and maximum published pre-Euro American settlement FRI estimates.

Understanding the controls on fire regimes is important for effective fire management. For simplicity, controls can be organized into four broad categories—fuel production (i.e., fuel load), fuel structure (e.g., bulk density, surface area-to-volume ratio), climate (i.e., those aspects of climate with relatively direct influence on fire behavior, including patterns of relative humidity and wind), and ignitions.[14] The remainder of this discussion focuses on explaining the controls on FRI for a representative subset of PFRs within PG&E's service territory. PFRs were chosen for inclusion in the subset with the intent of balancing the need to capture the greatest possible proportion of the service territory, as well as the need to capture as much as possible of the service territory's diversity in fire ecology, while also keeping the number of PFRs reasonably small. The chosen PFRs are oak woodlands, mixed conifer (a consolidation of the yellow pine, dry mixed conifer, and moist mixed conifer PFRs), red fir, and chaparral and serotinous conifers.

14 Krawchuk et al. (2009); Pausas and Keeley (2009); Bowman et al. (2017).

- Oak Woodland: Vegetation types included in the oak woodland PFR generally consist of an oak (*Quercus* spp.) -dominated overstory with a continuous herbaceous understory of grasses and forbs. In PG&E's service territory, these vegetation types primarily occur in the foothills of the Sierra Nevada and coast ranges. Prior to Euro-American settlement, FRI were likely relatively short (Figure PG&E-5.3.1-2).[15] Fires were primarily surface fires, carried by dead herbaceous surface fuels, and, as a result, burned areas rapidly regained the ability to support fire again, such that fuel was rarely a limiting factor for fire occurrence.[16] Moreover, the annual occurrence of prolonged hot, dry periods in these areas meant that these fuels were receptive to fire for a large portion of every year. Rates of natural ignitions were likely low.[17] However, these were substantially augmented by purposeful aboriginal ignitions. These ignition sources, in combination with the regular presence of continuous and receptive fuel, reasonably explain the relatively short FRIs that characterized oak woodland vegetation types prior to Euro-American settlement. Following Euro-American settlement, FRIs in oak woodland vegetation types have increased significantly (Figure PG&E-5.3.1-2). Although potentially partly explained by the dramatic reduction in purposeful aboriginal ignitions, this is somewhat compensated by modern accidental ignitions. More likely, the increase in FRI is due to the intensive fragmentation of foothill landscapes, coupled with the introduction of effective fire suppression.[18] This description of fire in vegetation types of the oak woodland PFR, also likely applies to those belonging to the grasses and forbs PFR.

- Mixed Conifer: Due to their similarities in species composition, vegetation structure, and fire regime, the yellow pine, dry mixed conifer, and moist mixed conifer PFRs are combined into a single "mixed conifer" category for the purpose of discussing controls on FRI. Vegetation types included in the mixed conifer PFRs typically consist of a forest or woodland overstory dominated by multiple conifer species (*Pinus* spp., *Abies concolor*, *Calocedrus decurrens*), with a sparse understory of shrubs, grasses, and forbs. In PG&E's service territory, these vegetation types primarily occur in the middle elevations of the Sierra Nevada, southern Cascades, Klamath Mountains, and coast ranges. Prior to Euro-American settlement, FRIs were likely relatively short (Figure PG&E-5.3.1-2).[19] Fires were primarily of low and moderate intensity, carried largely by leaf litter and other small-diameter dead surface fuel, with limited burning of the live forest canopy.[20] Once burned, areas typically regenerated sufficient surface fuel to support fire again within a few years, though not as rapidly as oak woodland vegetation types. Summers were relatively hot, dry, and long, and ignitions from natural and human sources were moderately

15 Van de Water and Safford (2011).

16 Wills (2006).

17 van Wagtendonk and Cayan (2008).

18 Wills (2006).

19 Van de Water and Safford (2011).

20 van Wagtendonk and Fites-Kaufman (2006).

frequent.[21] This combination of longer post-fire recovery periods, coupled with more frequent ignitions, suggests that fuel was a major constraint on FRIs in mixed conifer vegetation types during the pre-Euro-American settlement period. With Euro-American settlement, FRIs in mixed conifer vegetation types have lengthened dramatically (Figure PG&E-5.3.1-2), initially as a consequence of both major declines in the rates of purposeful aboriginal ignitions, as well as landscape fragmentation due to intensive logging and grazing, then later exacerbated by the introduction of effective fire suppression.[22] These changes have led to increases in fuel continuity and fuel load, with the result that fire occurrence is now more constrained by ignitions and climate, than it is by fuel.[23]

- Red Fir: Vegetation types in the red fir PFR typically consist of a forest or woodland overstory dominated by red fir (*Abies magnifica*), with a significant understory of shrubs and herbaceous grasses and forbs. In PG&E's service territory, these vegetation types primarily occur at the upper elevations of the Sierra Nevada, southern Cascades, Klamath Mountains, and Northern Coast Range. Before Euro-American settlement, FRI varied considerably, both locally and regionally, but on average was most likely moderately long (Figure PG&E-5.3.1-2).[24] Likewise, fire intensity was also variable, with some fires burning primarily in the surface fuel, and others also burning significant areas of live forest canopy.[25] These moderately long FRIs can be explained by the combination of several factors. First, landscapes containing red fir vegetation types often also contain an abundance of natural fuel breaks such as rock outcrops and wet meadows, constraining the size of individual fires. Second, at these high elevations, winters are long and growing seasons are short, such that fuel accumulation is slow. Third, due both to red fir's short needles and to the annual prolonged compaction by snowpack, surface fuel in red fir vegetation types is very dense and therefore resistant to flaming combustion except under extremely dry and windy conditions. Fourth, due to long winters, surface fuel is dry for only a relatively small portion of the year. Finally, red fir vegetation types experienced relatively few purposeful aboriginal ignitions, and while lightning strikes are frequent, they often coincide with precipitation such that ignitions are less likely to result.[26] Although fuel, ignitions, and climate all played a role in controlling FRI prior to Euro-American settlement, climate likely played a larger role in red fir vegetation types than it did in most vegetation types in warmer climates, such as those belonging to the oak woodland and mixed conifer PFRs. Since Euro-American settlement, fire suppression has led to an increase in FRI (Figure PG&E-5.3.1-2). This, combined with warming-driven increases in rates of fuel production, have led to increases in fuel continuity and load in red fir vegetation

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21 van Wagtendonk and Fites-Kaufman (2006); van Wagtendonk and Cayan (2008).

22 van Wagtendonk and Fites-Kaufman (2006).

23 Westerling et al. (2006); Steel et al. (2015).

24 Van de Water and Safford (2011).

25 van Wagtendonk and Fites-Kaufman (2006); Skinner and Taylor (2006).

26 van Wagtendonk and Cayan (2008).

types,[27] which have likely further heightened the sensitivity of fire occurrence to variation in climate and ignition frequency.

- Chaparral and Serotinous Conifers: Vegetation types in the chaparral and serotinous conifer PFR typically consist of a single layer of vegetation composed of large shrubs (e.g., *Adenostema fasciculatum*, *Arctostaphylos spp.*, *Ceanothus spp.*) or short-statured conifers (*Pinus spp.*, *Hesperocyparis spp.*), with little to no overstory or understory vegetation. In PG&E's service territory, these vegetation types primarily occur at the lower elevations of the Sierra Nevada, southern Cascades, and coast ranges. Prior to Euro-American settlement, FRIs were generally relatively long, albeit variable (Figure PG&E-5.3.1-2).[28] Fires were usually very intense, carried primarily by standing live and dead shrubs and trees. Summers in these relatively low-elevation sites were hot, dry, and long, such that fuel was receptive to fire for much of the year, although a disproportionately high amount of the area burned may have occurred under extreme weather events. Once burned, these vegetation types generally required more time than mixed conifer vegetation types to regrow sufficient fuel to support fire again, at least under mild or moderate fire weather conditions. Although aboriginal ignitions were significant, and significant burning likely resulted from the spread of fire from adjacent frequent-fire vegetation types (i.e., oak woodland and mixed conifer), natural and direct ignition in chaparral and serotinous conifer vegetation types from lightning were relatively infrequent.[29] As a result, although the relative influence of fuels, climate, and ignitions on fire occurrence certainly varied across the wide geographic distribution of this PFR, the importance of climate and ignitions likely outweighed that of fuel prior to Euro-American settlement.[30] Within PG&E's service territory, current FRI for this PFR is, on average, similar to those that existed prior to Euro-American settlement (Figure PG&E-5.3.1-2). This contrasts with the other vegetation types discussed in this narrative but is not entirely surprising for at least two reasons. First, while rates of purposeful aboriginal ignitions decreased markedly following Euro-American settlement, those decreases may partially be compensated by rates of modern accidental ignitions. Second, while fire suppression efforts have clearly been effective in increasing FRI in vegetation types where fire intensities are characteristically low or moderate, it is doubtful that fire suppression efforts have been as effective in chaparral and serotinous conifer vegetation types where fire intensities are typically high. This description of fire in vegetation types of the chaparral and serotinous conifers PFR, also likely applies to those belonging to the coastal sage scrub PFR.[31]

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27 Dolanc et al. (2013).

28 Van de Water and Safford (2011); Keeley et al. (2012).

29 van Wagtendonk and Cayan (2008); Keeley et al. (2012).

30 Keeley et al. (2012).

31 Keeley et al. (2012).

5.3.2 Catastrophic Wildfire History

The electrical corporation must provide a brief narrative summarizing the wildfire history for the past 20 years (2002-2022) as recorded by the electrical corporation, California Department of Forestry and Fire Protection (CAL FIRE), or another authoritative sources. For this section, wildfire history must be limited to electric 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 California Public Utilities Commission (CPUC) that may be attributable to facilities or equipment owned by the electrical corporation and where the cause of the ignition is still under investigation. Electrical corporations must clearly denote those ignitions as still under investigation. In addition, the electrical corporation must provide catastrophic wildfire statistics in tabular form, including the following key metrics:

- *Ignition date;*
- *Fire name;*
- *Official cause (if known);*
- *Size (acres);*
- *Number of fatalities;*
- *Number of structures damaged; and*
- *Estimated financial loss (U.S. dollars).*

The Table below provides an example of the content and level of detail required for the tabulated historical catastrophic utility-related wildfire statistics. The electrical corporation must provide an authoritative government source (i.e., CPUC, CAL FIRE, USFS, or local CAL FIRE authority) for its reporting of wildfire history data and loss/damage estimates, to the extent this information is available.

The electrical corporation must also provide a map or set of maps illustrating the catastrophic wildfires. One representative map must appear in the main body of the Wildfire Mitigation Plan (WMP), with supplemental or detailed maps provided in Appendix C as needed. The maps must include the following:

- *Fire perimeters;*
- *Legend and text labeling each fire perimeter; and*
- *County lines*

In compliance with CPUC Decision (D.) 14-02-015, PG&E began tracking wildfires potentially associated with our electric facilities in 2014. Since that time, PG&E has tracked and investigated 14 wildfires attributable to the utility in which at least one death occurred, 500 or more structures were damaged, or more than 5,000 acres burned. Table 5-4 provides additional details about these 14 incidents.

The information provided in the table below is based on information available to PG&E at the time of the 2023 WMP filing. PG&E requested wildfire data from CAL FIRE in December 2022 for fires occurring between 2002 and 2014 in an attempt to provide additional information responsive to the Guidelines. The information provided in mid-January did not provide sufficient information to meaningfully respond further to this request.

TABLE 5-4:
UTILITY-RELATED CATASTROPHIC WILDFIRES WITHIN PG&E'S SERVICE TERRITORY

Ignition Date	Fire Name[c]	Fire Size (acres)	No. of Fatalities	No. of Structures Destroyed and Damaged	Financial Loss ($ millions)[a]
9/9/2015	Butte	70,868	2	965	$71
8/29/2017	Railroad	12,407	–	–	$3
10/8/2017	Nuns Complex	245,000	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
9/6/2022	Mosquito[b]	76,788	–	–	Unknown

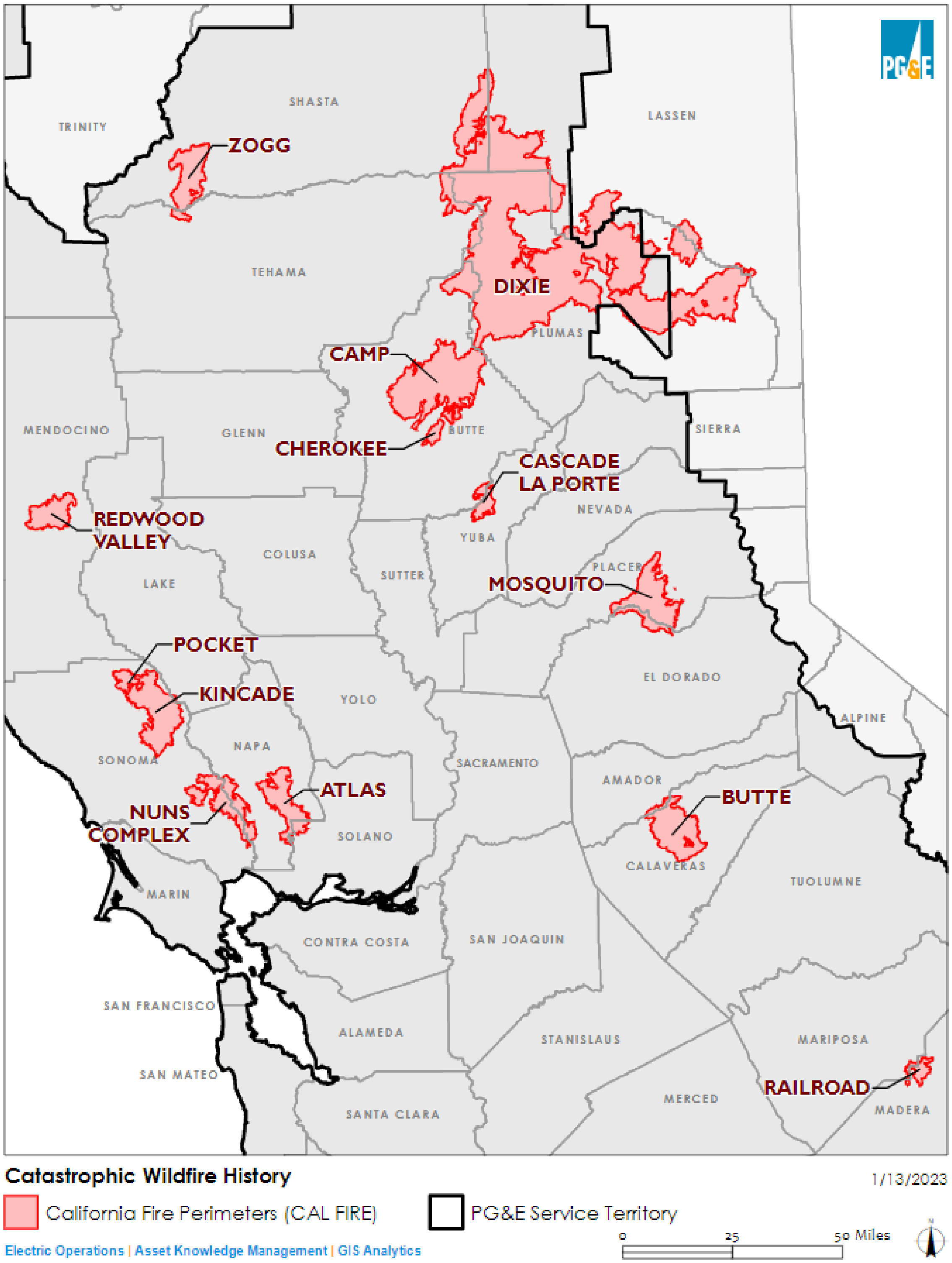
(a) Financial loss information provided by CAL FIRE was combined for some fires. In these cases, the total financial loss was divided evenly among the individual fires. CAL FIRE combined financial loss for the Cascade and LaPorte fires and the Nuns Complex, Atlas, and Pocket fires.

(b) The Mosquito Fire is under investigation and has not been attributed to PG&E's equipment at this time.

(c) Data in this table comes from the CAL FIRE website (excluding financial loss).

Figure 5.3.2-1 below is a map illustrating the Utility-Related Catastrophic Wildfires Within PG&E's Service Territory. Additional maps illustrating the individual 14 catastrophic wildfires listed in Table 5-4 above are included in Appendix C.

FIGURE 5.3.2-1:
UTILITY-RELATED CATASTROPHIC WILDFIRES WITHIN PG&E'S SERVICE TERRITORY MAP



Note:

- The Mosquito Fire is under investigation and a final cause has not been determined.
- For additional map viewing instructions, please refer to Appendix C.

5.3.3 High Fire Threat District

The electrical corporation must provide a brief narrative identifying the CPUC-defined HFTD across its territory. The electrical corporation must also provide a map of its service territory overlaid with the HFTD. The map must be accompanied by tabulated statistics on the CPUC-defined HFTD including the following minimum information:

- *Total area of the electrical corporation's service territory in the HFTD (sq. mi.); and*
- *The electrical corporation's service territory in the HFTD as a percentage of its total service territory (%).*

For the HFTD map, the HFTD layer(s) (raster or polygon) must cover the electrical corporation's service territory and the HFTD layer must match the latest boundaries as published by the CPUC.

The HFTD represents areas where there is an elevated hazard for utility-associated wildfires to occur and spread rapidly, and where communities face an elevated risk from utility-associated wildfires.[32] Specifically, Tier 2 and Tier 3 of the HFTD delineate areas with elevated risk and extreme risk, respectively, where "risk" is defined to include the likelihood and potential impacts on people and property.[33] In these HFTD areas, utilities are subject to stricter fire safety regulations, including General Order (GO) 95.

In addition to the CPUC-defined HFTD areas, PG&E has also identified High Fire Risk Areas (HFRA). The HFRA map is also used to inform workplans and conduct risk assessments. We developed our HFRA map starting with the HFTD Tier 2 and Tier 3 areas and adjusted it to include locations where an ignition during an offshore wind event could lead to a catastrophic wildfire. PG&E continues to refine our HFRA.[34]

The geographic extent of the current HFTD Tiers are shown in Figure PG&E-5.3.3-1 and quantified in Table 5-5.

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32 D.17-01-009, p. 2; D.17-06-024, p. 2.

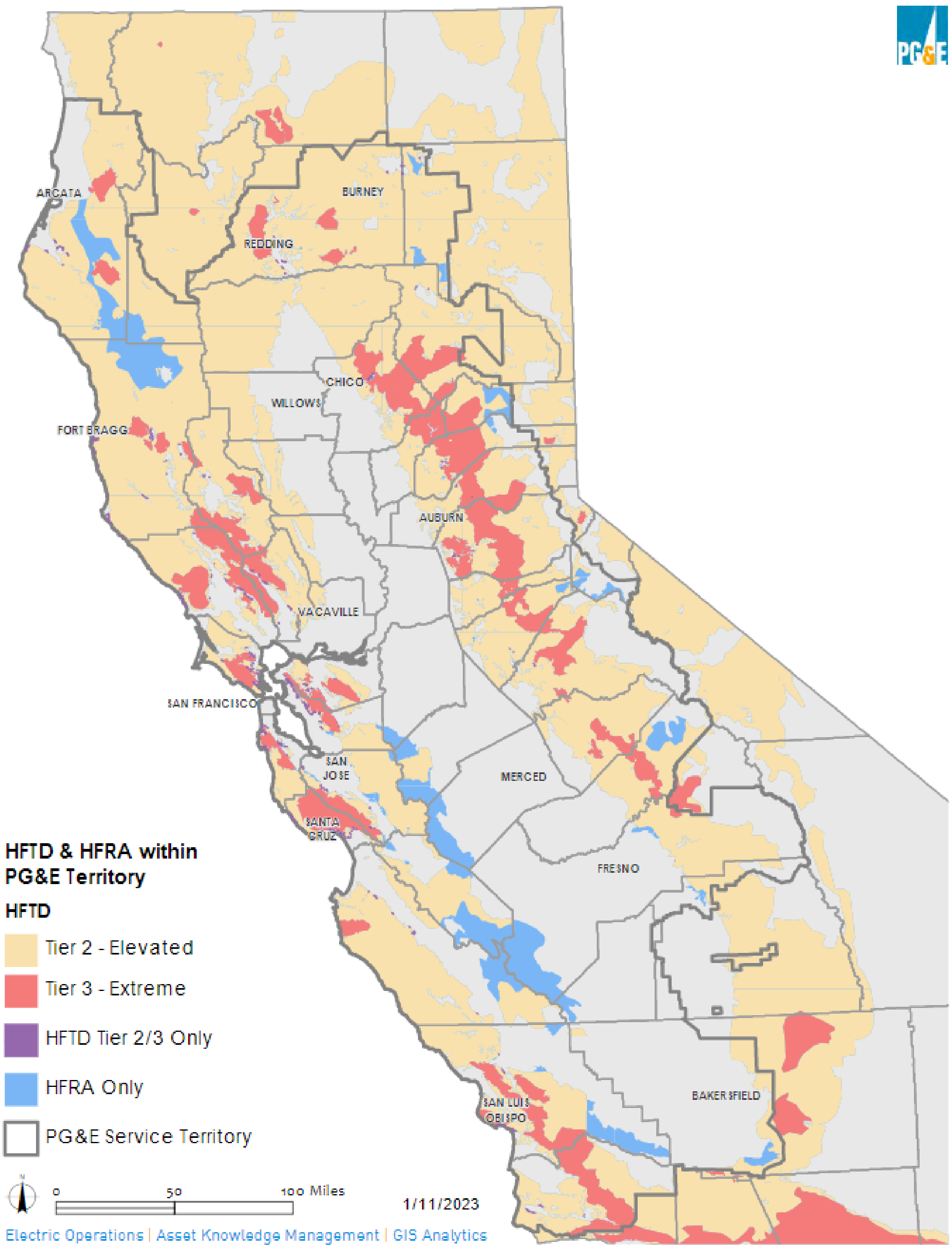
33 D.17-01-009, p. 25 and D.17-06-024, p. A-13 broadly define Tier 2 and Tier 3 of the CPUC's HFTD map as "[a]reas with elevated wildfire risk" and "[a]reas with extreme wildfire risk," respectively. A set of more explicit definitions is given in the Rulemaking (R.) 15-05-006, Independent Review Team Final Report on the Production of the CPUC's Statewide Fire Map 2 (Nov. 21, 2017), at pp. 11-12 and reiterated in D.20-12-030, p. 2, and on the CPUC's Fire-Threat Maps and Fire-Safety Rulemaking webpage, available at: <https://www.cpuc.ca.gov/industries-and-topics/wildfires/fire-threat-maps-and-fire-safety-rulemaking>, accessed January 26, 2023.

34 The processes PG&E used to develop the HFRA were described in PG&E's 2021 and 2022 WMPs. See PG&E's 2021 WMP (June 3, 2021), starting at p. 85, and PG&E's 2022 WMP (Feb. 25, 2022), starting at p. 75.

**TABLE 5-5:
PG&E'S SERVICE TERRITORY IN THE HFTD TIER 1, TIER 2, AND TIER 3
AS OF DECEMBER 2022**

Fire Threat Map Product	Sq. Mi. in PG&E Service Territory	Proportion of PG&E's Service Territory
Non-HFTD/Tier1	33,812	47%
HFTD Zone 1	33	0.05%
HFTD Tier 2	31,797	44%
HFTD Tier 3	6,090	8%

FIGURE PG&E-5.3.3-1:
HFTD TIER 2 AND TIER 3, AND PG&E'S HFRA, NOVEMBER 2022



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

5.3.4 Climate Change

5.3.4.1 General Climate Conditions

The electrical corporation must provide an overview of the general weather conditions and climate across its service territory in the past 30- to 40-year period. The narrative must include, at a minimum, the following:

- *Average temperatures throughout the year;*
- *Extreme temperatures that may occur and when and where they may occur; and*
- *Precipitation throughout the year.*

The electrical corporation must also provide a graph of the average precipitation and maximum and minimum temperatures for each distinct climatic region of its service territory. At a minimum, it must provide one graph in the main body of the report. Figure 5-2 provides an example of the climate/weather graph.

In general, weather conditions in California are cooler along the coast due to the influence of the marine layer and in the higher elevations of the Sierra Nevada. Hotter temperatures, especially during summer, are located away from the coast in low elevation, interior valleys.

The average temperature in California throughout the year is shown in Figure 5-2-1 below.[35]

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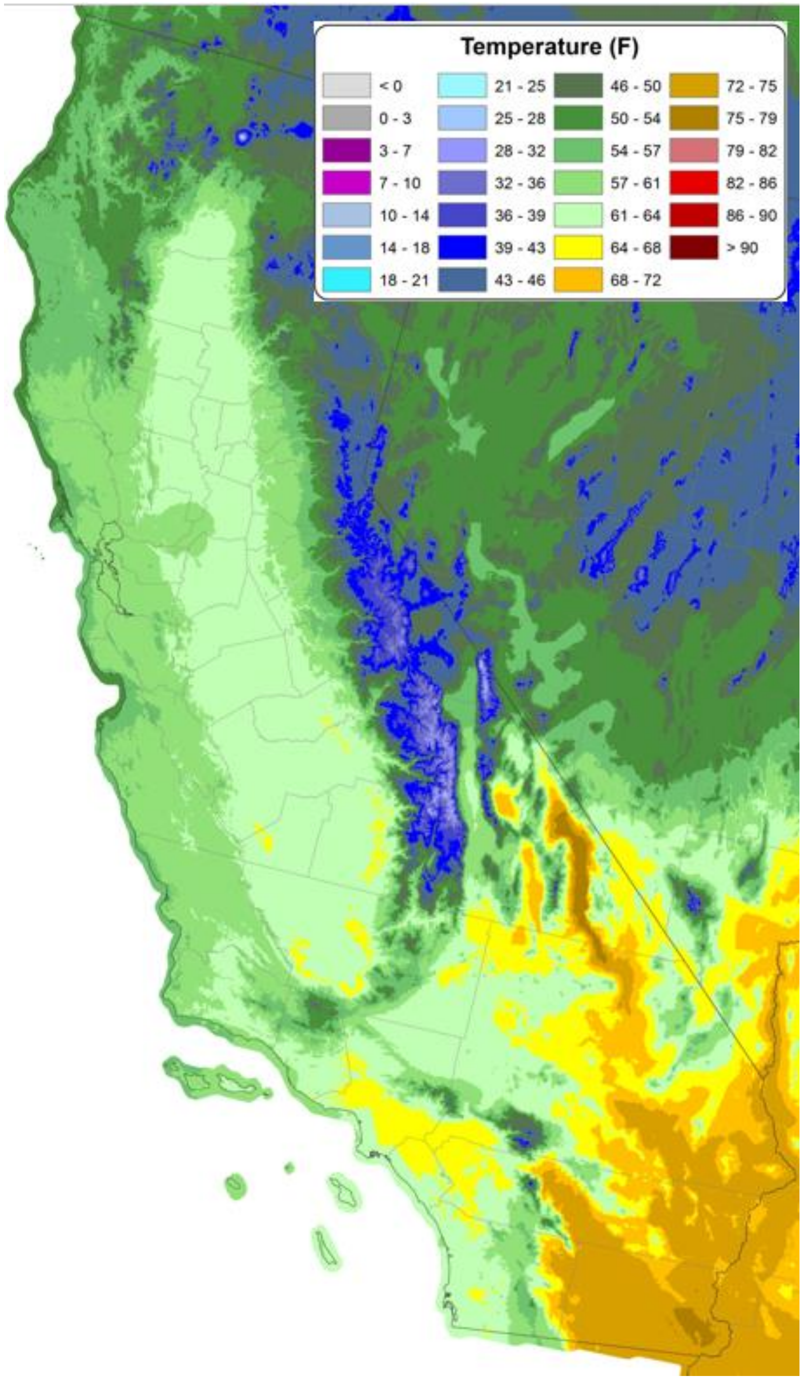
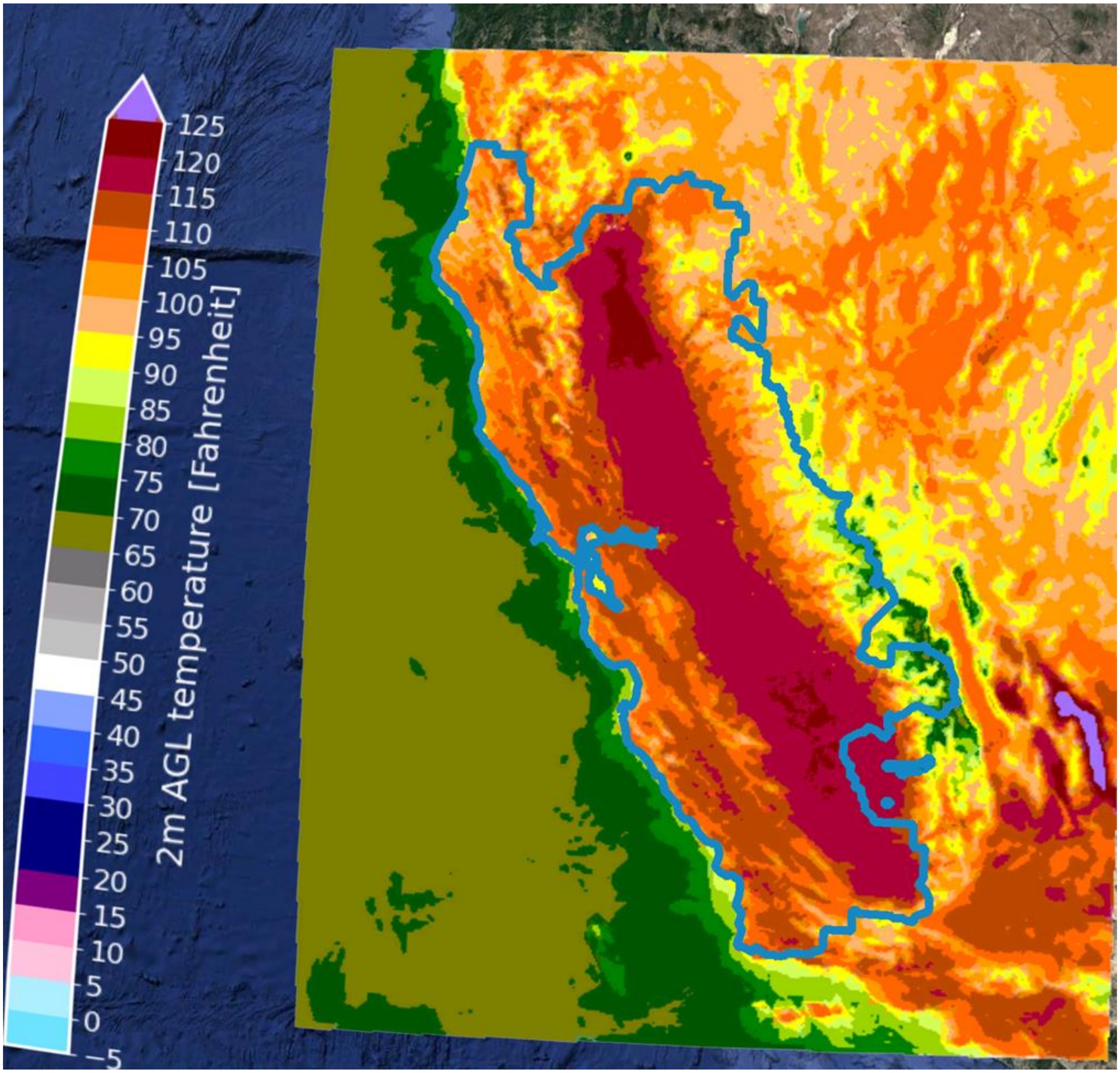
35 Oregon State University, PRISM Climate Group, Northwest Alliance for Computational Science and Engineering, data from 1990 to 2020. Data is available and can be downloaded at: <https://prism.oregonstate.edu/normals/>, accessed January 27, 2023.

FIGURE 5-2-1:
AVERAGE TEMPERATURE IN CALIFORNIA 1990-2020



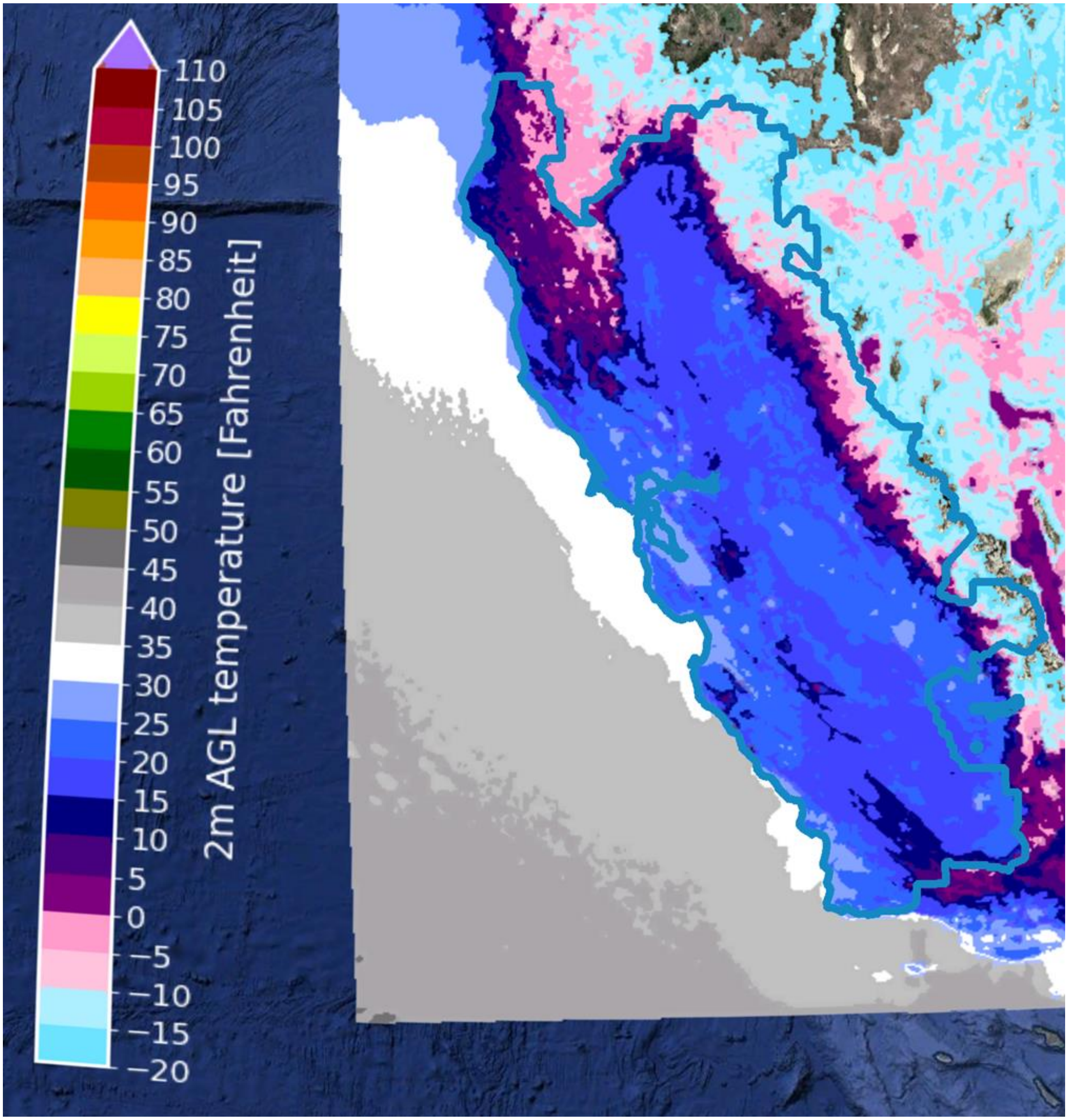
Extreme temperatures can be assessed from a 30+ year, hourly climatology of temperatures in our service territory. The maps below show the maximum temperature (Figure 5-2-2) and minimum temperature (Figure 5-2-3) in each 2 x 2-kilometer grid cell in our weather climatology from 1989 to 2021. The hottest temperatures are located in the low elevation interior valleys, while cooler conditions are located along the coast and high elevations. These extreme temperatures generally occur from June through September.

FIGURE 5-2-2:
MAXIMUM TEMPERATURE IN CALIFORNIA 1998-2021



Source: PRISM Climate Group at Oregon State University.

FIGURE 5-2-3:
MINIMUM TEMPERATURE IN CALIFORNIA 1998-2021



Source: PRISM Climate Group at Oregon State University.

In general, the highest precipitation amounts occur across the elevated terrain in the state due to orographic forcing.[36] The topography of California forces air to ascend during events leading to enhanced precipitation on one side of a large topographic feature and a rain shadow effect on the other side. For example, this causes a large gradient in precipitation amounts from the higher elevations of the Sierra to the Owens valley.

Precipitation is highly variable in California year-over-year and is dependent on the number and severity of winter storm events that occur. The bar chart below (Figure 5-2-5) shows the total amount of precipitation in inches for each water year from 1921 to 2021.[37]

The average annual precipitation accumulation is shown in Figure 5-2-4 below.[38]

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36 The topography—or shape and features of the area—can cause clouds to be formed. When air is forced to rise over a barrier of mountains or hills it cools as it rises. https://en.mimi.hu/meteorology/orographic_forcing.html.

37 See <https://cdec.water.ca.gov/reportapp/javareports?name=8STATIONHIST>, accessed January 27, 2023. The California Data Exchange Center (CDEC) website also contains data for other indices for the central and southern Sierra, but were not reproduced here.

38 Oregon State University, PRISM Climate Group, *supra*, available at: <https://prism.oregonstate.edu/normals/>, accessed January 27, 2023.

FIGURE 5-2-4:
AVERAGE ANNUAL PRECIPITATION ACCUMULATION

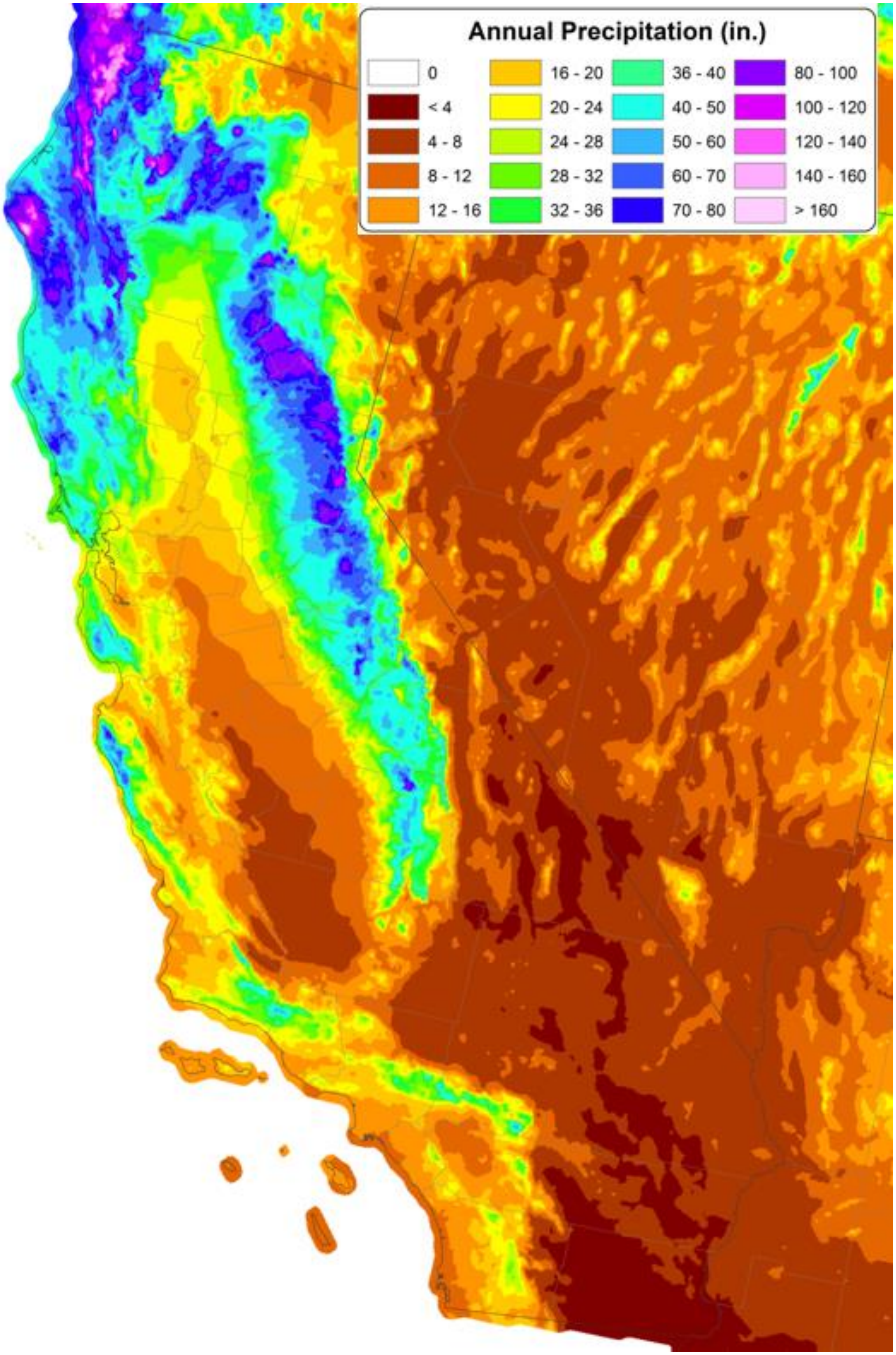
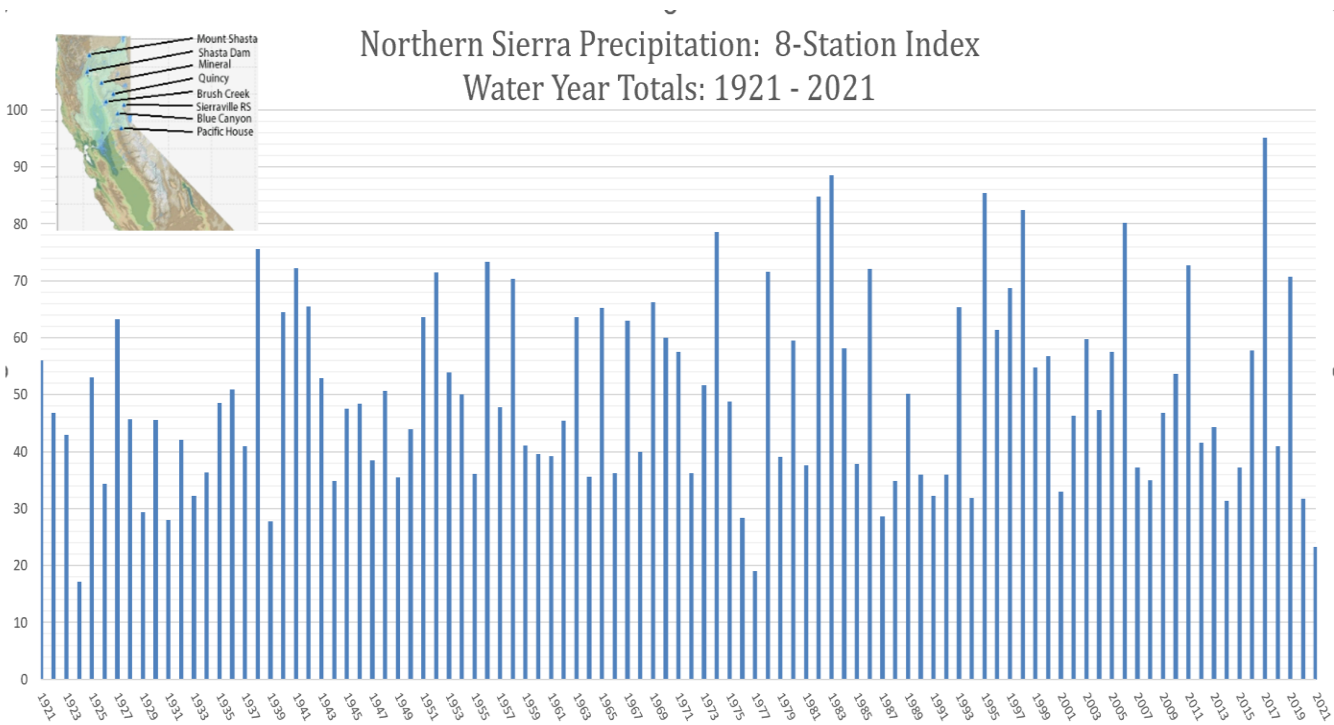


FIGURE 5-2-5:
NORTHERN SIERRA WATER TOTALS 1921-2021



5.3.4.2 Climate Change Phenomena and Trends

The electrical corporation must provide a brief discussion of the local impacts of anticipated climate change phenomena and trends across its service territory. In addition, the electrical corporation must provide graphs/charts illustrating:

- *Mean annual temperature (Figure 5-3);*
- *Mean annual precipitation (Figure 5-4); and*
- *Projected changes in minimum and maximum daily temperatures (Figure 5-5).*

The electrical corporation must also indicate the increase in extreme fire danger days (historic 95th-percentile conditions) due to climate change, considering (at a minimum) the combination of warmer temperatures, drier vegetation, and changes in high-wind events (i.e., Santa Ana winds, Diablo winds, Sundowners) for both winter/spring and summer/fall periods throughout the electrical corporation service territory. Figure 5-6 provides an example of the required information on projections of extreme fire dangers.

The electrical corporation must cite all source(s) used to write and illustrate this section.

PG&E is providing links that provide the required information for our service territory as opposed to providing graphs in this document:

- Figure 5-3: Mean annual temperature – https://cal-adapt.org/tools/annual-averages.
- Figure 5-4: Mean annual precipitation – https://cal-adapt.org/tools/annual-averages.
- Figure 5-5: Projected changes in minimum and maximum daily temperatures – https://cal-adapt.org/tools/maps-of-projected-change.

We have not reproduced these graphs in this section of our WMP as they are interactive and customizable and the best way to view them is online where they are available to the public.

Figure 5-6: Projected extreme fire dangers – PG&E is not aware of existing research that would allow us to respond to the Office of Energy Infrastructure Safety's (OEIS or Energy Safety) question about the increase in extreme fire danger days due to climate change, considering the combination of warmer temperatures, drier vegetation, and changes in high-wind events for both winter/spring and summer/fall periods throughout our service territory because the relationship between the environmental variables of long-term climate projects and localized weather occurrences are still being researched and established.

Climate change poses both near and long-term risks to California, including more frequent and extreme drought, precipitation events, and wildfires, as well as rising temperatures and sea levels.

We face increased reliability and capacity risks because of changes in mean annual and extreme temperatures. Extreme, and especially prolonged, high temperatures can result in equipment failure due to damage from high heat and/or from increased load resulting in customer outages. Averaged across PG&E's service territory, mean annual temperatures are projected to increase by 3 degrees Fahrenheit (°F) by 2030 and 5°F by 2050.[39] Across PG&E's service territory, temperatures occurring during the seven hottest days of the year are projected to increase from an average baseline of 102°F up to 106°F in 2030 and up to 109°F in 2050.[40] Sutter County is projected to see the highest temperatures during these seven hottest days, with temperatures reaching or exceeding 110°F in an average year.[41] Across PG&E's service territory the hottest temperature occurring once every ten years may increase by 6°F by 2030 and by 9°F by 2050, relative to a historical baseline of 109°F.[42] Alpine and Sierra counties are projected to experience the greatest change in these extreme high temperatures.[43]

Increased temperatures can cause electric equipment to age more quickly which will increase the need for more frequent asset replacements. Higher temperatures may cause equipment to fail resulting in customer outages. Electricity demand increases in response to increases in temperature, driving higher peak loads as our customers use air conditioning more frequently.

Due to climate change, we are likely to experience more intense, heavy precipitation events and more large storm events. By 2050, the greatest projected increase in average annual 5-day maximum precipitation amount is 31 percent in Alpine County, and 23 percent across the service territory.[44] With increased precipitation we may see flooding that could cause direct equipment damage and could hinder access to equipment during an extreme weather event and impact outage restoration efforts.

Per CPUC requirement, we use CAL ADAPT, which is the public data repository for the climate data that underpins California's Climate Change Assessments, to characterize future natural conditions and evaluate the impact of those conditions on PG&E's ability to deliver safe, clean, reliable, affordable energy. This includes changes in mean annual temperatures, precipitation, and extremes. Data and images requested as part of this section can be found at the CAL ADAPT website.[45] As stated above, we have

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39 Values provided are a result of analysis associated with PG&E's Climate Vulnerability Assessment (R.18-04-019) using publicly available data via CAL ADAPT. Analysis performed using Representative Concentration Pathway 8.5 and the boundaries of PG&E's service territory.

40 *Ibid.*

41 *Ibid.*

42 *Ibid.*

43 *Ibid.*

44 *Ibid.*

45 The CAL ADAPT website is available at: https://cal-adapt.org/>, accessed January 27, 2023. (Select the "Tools" link, and then the "For the Maps of Projected Change" link.)

not reproduced those graphs because they are interactive and customizable and the best way to view them is online.

A November 2021 paper published in Science Advances by researchers at the University of California, Irvine (Cal Irvine Paper)[46] provides an overview of the state of knowledge regarding the relationship between climate change projections and wildfire occurrence and burned area. Until very recently (2021), most studies of the effect of climate change on future wildfire trends have relied on annual or monthly burned area statistics (see CAL-ADAPT's wildfire scenario projection tool as an example). As noted in the Cal Irvine Paper, "an improved attribution of recent increase in burned area is needed for better predictions of future fire activity and for the design of forest management strategies but remains challenging given the wide range of possible drivers and interactions among them."[47] These drivers include fire suppression and land use change, population growth and housing development in the Wildland-Urban Interface (WUI), and climate change, "with observations providing evidence of hotter, drier, conditions during summer and a longer fire season."[48]

The Cal Irvine Paper advances wildfire projection science by combining daily meteorological conditions with observed fire occurrence and daily burned area, using the resulting statistical relationships to reconstruct past and project future changes in fire number and burned area.[49] This study is specific to summer months in California's Sierra Nevada.

The Cal Irvine Paper finds a meaningful statistical relationship between high daily temperature and fire occurrence and burned area, suggesting that climate projections of future daily temperatures may be used to better estimate the number and extent of future wildfires. Ultimately, the study estimates "that increasing summer temperature extremes will increase the number of fires by 51+- 32 percent through the 2040s relative to a 2011-2020 baseline,"[50] and that "high daily temperature extremes have a disproportionate effect on fire activity, likely as a consequence of fine fuel drying." [51]

As the author's note frequently throughout the Cal Irvine Paper, the study only considers one wildfire-related factor (summer daily temperature) and other climate change impacts on ecosystem function and fire dynamics are expected that may either dampen or strengthen projected changes in fire activity.[52] Some of these variables have been characterized in existing climate projections, but many have not due to the

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46 Gutierrez et al., *Wildfire Response to Changing Daily Temperature Extremes in California's Sierra Nevada*, (Nov. 17, 2021) Science Advances, available at: <https://www.science.org/doi/10.1126/sciadv.abe6417>, accessed January 27, 2023.

47 *Ibid.*

48 *Ibid.*

49 *Ibid.*

50 *Ibid.*

51 *Ibid.*

52 *Ibid.*

mismatch in geographic and temporal specificity between climate projections and meteorological observations or because they are not primarily climate-driven, like demographic growth in the WUI.

Another illustrative study[53] considers the implications of projected changes in "reference evapotranspiration" (a standardized measurement of the thirst of the atmosphere) on wildfire danger and drought in California and Nevada.[54] Climate models project an increase in reference evapotranspiration through the end of the century, with increased air temperature due to climate change as the greatest contributor to increased evapotranspiration demand. The study finds that the likelihood of extreme wildfire potential based on increased evaporative demand during summer and autumn "increases substantially."[55]

This type of research is useful in two ways that are relevant to answering this question:

- First, it advances the state of climate science and our understanding of which environmental relationships are most important in evaluating and characterizing future wildfire risk, laying the groundwork for more accurate and temporally and geographically granular projections in the future. PG&E expects we will have more to share in response to this question in the future as research continues to advance and findings from California's 5th Climate Change Assessment (expected in 2023) become available; and

- Second, these studies confirm that historically extreme wildfire risk in California is not expected to diminish, and instead, will increase. This is consistent with previous PG&E research findings included in PG&E's 2020 WMP,[56] 2021 WMP[57] and 2022 WMP[58] that compare current HFTD and HFRA maps with projected wildfire burn areas in 2050 using CAL-ADAPT data. The research shows that wildfire risk will intensify in existing high wildfire risk zones and spread along the margins of existing high wildfire risk zones.

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53 McEvoy et al., Projected Changes in Reference Evapotranspiration in California and Nevada: Implications for Drought and Wildland Fire Danger (Oct. 29, 2020) ("McEvoy et al. 2020 Study").

54 McEvoy et al. 2020 Study, available at: <https://agupubs.onlinelibrary.wiley.com/doi/full/10.1029/2020EF001736>, accessed January 26, 2023.

55 *Ibid.*

56 Rulemaking 18-10-007 (R.), PG&E's 2020 Wildfire Mitigation Plan Report, Updated, February 20, 2020, Section 5.3.1.2, pp. 5-45 to 5-47.

57 PG&E's 2021 WMP, Response to Revision Notice, June 3, 2021, Section 7.3.1.2, pp. 427-430.

58 PG&E's 2022 Wildfire Mitigation Plan – Final Revision Notice Response (Docket #2022-WMPs), July 26, 2022, Section 7.3.1.2, p. 386.

PG&E's Climate Resilience, Meteorology, and Community Wildfire Safety groups continue to monitor, coordinate, and participate in work to advance near-term mechanistic wildfire models, as well as long-term climate projections in order to continue to improve and optimize decision-making.

5.3.5 Topography

The electrical corporation must provide an overview and brief description of the various topographic conditions across its service territory.

Figure PG&E-5.3.5-1 below shows the topographic elevation ranges throughout PG&E's service territory. The topographic conditions across our service territory are highly variable, but are binned into a series of geomorphic provinces by the California Geological Survey (CGS).[59] General descriptions of the topographic conditions and associated major land cover types by geomorphic province are provided below.

Coast Ranges

The Coast Ranges province is a northwest-trending strip extending from the Pacific Ocean coastline eastward some tens of miles to the western edge of the Great Valley. This terrain includes a range of hills and low mountains that rise from the coast to crest elevations typically between 1,000 to 4,000 feet (ft.) above sea level. The active San Andreas fault system trends through the Coast Ranges and distinctive fault-developed narrow valleys and hills occur along the fault zone. Along the coast, the province includes coastal bays, estuaries and hills with incised river valleys that drain into the ocean. The east margin of the province generally consists of rolling hills grading down to the Great Valley. Vegetation cover in the Coast Ranges varies from thick brush and oak forests in the south, transitioning to multistory fir and redwood forests in the north.

Great Valley

The Great Valley province is an elongated, northwest trending interior valley between the Coast Ranges and Sierra Nevada provinces. The Great Valley is formed by the Sacramento and San Joaquin River valleys that coalesce and drain into San Francisco Bay via the Sacramento-San Joaquin Delta. Elevations are low in this province, slopes are gradual, and the ground is extensively developed for agriculture. Low marshy areas and alluvial floodplains border the Sacramento and San Joaquin Rivers in the interior of the Great Valley, and slopes along the margins of the valley transition to the foothill slopes of the adjacent Coast Ranges and Sierra Nevada. Some low interior hills covered by oak forests and scrub occur within the Great Valley.

Sierra Nevada

The Sierra Nevada province is a northwest trending mountain range with a high crest rising typically to elevations of between 6,000 to 14,000 ft. The Sierra Nevada range is tilted westward with a gentler western slope and steep escarpment on the east side.

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59 A CGS publication highlights California's geomorphic provinces, which "are naturally defined geologic regions that display a distinct landscape or landform." CGS, Note 36, California Geomorphic Provinces, dated Dec. 2002, available at: <https://www.conservation.ca.gov/cgs/Documents/Publications/CGS-Notes/CGS-Note-36.pdf>, accessed January 26, 2023.

Deep river canyons drain from the Sierra Nevada crest to the Sacramento and San Joaquin Rivers in the Great Valley. The Sierra Nevada has extensive rugged and steep topography, along with some large interior valleys and low bordering foothills that transition to the Great Valley. Vegetation in the Sierra Nevada follows a classic mountain zonation with dense scrub and oak-pine forests in the lower foothills, dense fir and pine forests in the middle elevations, and fir-alpine vegetation in the high elevations.

Mojave Desert

The extreme southeast portion of the service territory extends into the arid Mojave Desert province. Terrain in this province is varied and includes isolated mountain ranges, broad low-lying valleys and playas, and steep canyons. The arid conditions support typical low desert brush, narrow riparian woods, and cactus.

Modoc Plateau/Cascade Range

The Modoc Plateau and Cascade Range provinces occur along the northernmost portion of the service territory. These provinces are volcanic terrain that include Mount Shasta and Mount Lassen volcanoes and associated cinder cones and lava flows, incised valleys, and intermountain valleys. Elevations typically range from about 3,000 to 6,000 ft., rising to 14,000 ft. at the summits of Mounts Shasta and Lassen. Vegetation consists of thick brush, oak-pine forests, and fir-alpine cover at highest elevations.

**FIGURE PG&E-5.3.5-1:
TOPOGRAPHIC MAP OF PG&E SERVICE TERRITORY AND ADJACENT PORTIONS OF CALIFORNIA WITH GEOMORPHIC PROVINCE BOUNDARIES**

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

5.4 Community Values at Risk

In this section of the WMP, the electrical corporation must identify the community values at risk across its service territory. Sections 5.4.1–5.4.4 provide detailed instructions.[60]

5.4.1 Urban, Rural, and Highly Rural Customers

The electrical corporation must provide a brief narrative describing the distribution of urban, rural, and highly rural areas and customers across its service territory. Refer to Appendix A for definitions.

PG&E's distribution of customers is broken down into three areas: urban, rural, and highly rural. Table PG&E-5.4.1-1 below shows the square miles in our service territory that correspond to the population density for highly rural, rural, and urban customers. Figure PG&E-5.1-1 shows the square miles in our service territory that correspond to the population density for highly rural, rural, and urban customers.

Population density numbers are calculated using the American Community Survey (ACS) 1-year estimates on population density by census tract for each corresponding year (2021 ACS 1-year estimate for 2021 metrics, 2022 ACS 1-year estimate for 2022 metrics, etc.). For years without an ACS 1-year estimate, we use the 1-year estimate immediately before the missing year.

PG&E calculates the number of customers in utility service areas that are in urban, rural, and highly rural regions each year by using population density by census tract based on population totals in the ACS – 2020. The population per square mile will be calculated for each census tract to define tracts as urban, rural, or highly rural.[61]

The number of customers within these regions will be calculated by providing a geospatial overlay of transformer locations as a proxy for the customer locations and summing up the number of service points associated with each transformer to obtain total customer count with the urban/rural/highly rural census tracts and then calculating the total number of meters within each urban, rural, or highly rural region type.

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60 *Annual information included in these sections should align with Table 7 from the QDRs.*

61 As defined in WMP Guidelines Appendix A (OEIS, 2023-2025 Wildfire Mitigation Plan Technical Guidelines (Dec. 6, 2022), Appendix A, p. A-8.), census tracts determined by the United States Bureau of the Census are used to define "areas," highly rural is defined as areas with a population of less than seven persons per sq. mi. in accordance with 38 Code of Federal Regulations 17.701, and rural and urban are defined as areas with a population of less than 1,000 persons per sq. mi. and areas with a population of more than 1,000 persons per sq. mi., respectively, in accordance with GO 165.

The sources of data used in the calculation of this information include Topologically Integrated Geographic Encoding and Referencing/Line with Selected Demographic and Economic Data – 2018, ACS – 2020, PG&E Geographic Information System (GIS) data layers.

TABLE PG&E-5.4.1-1:
SQUARE MILES IN PG&E'S SERVICE TERRITORY CORRESPONDING TO POPULATION DENSITY OF HIGHLY RURAL, RURAL, AND URBAN CUSTOMERS
(SUM OF SQUARE MILES)

Sum of Sq. Mi.	
Highly Rural	27,749.52
Rural	41,100.07
Urban	2,882.38

5.4.2 Wildland-Urban Interface

The electrical corporation must provide a brief narrative describing the WUI across its service territory. Refer to Appendix A for definitions.

PG&E's WUI is the line, area, or zone where structures and other human development meet or intermingle with undeveloped wildland or vegetation fuels (National Wildfire Coordinating Group). Enforcement agencies also designate the WUI as the area at significant risk from wildfires, established pursuant to Title 24, Part 2, Chapter 7A.

The population density of our customers per sq. mi. shows that 91 percent are classified as non-WUI (population density greater than 65,000) and 9 percent are WUI (population density greater than 6,000).

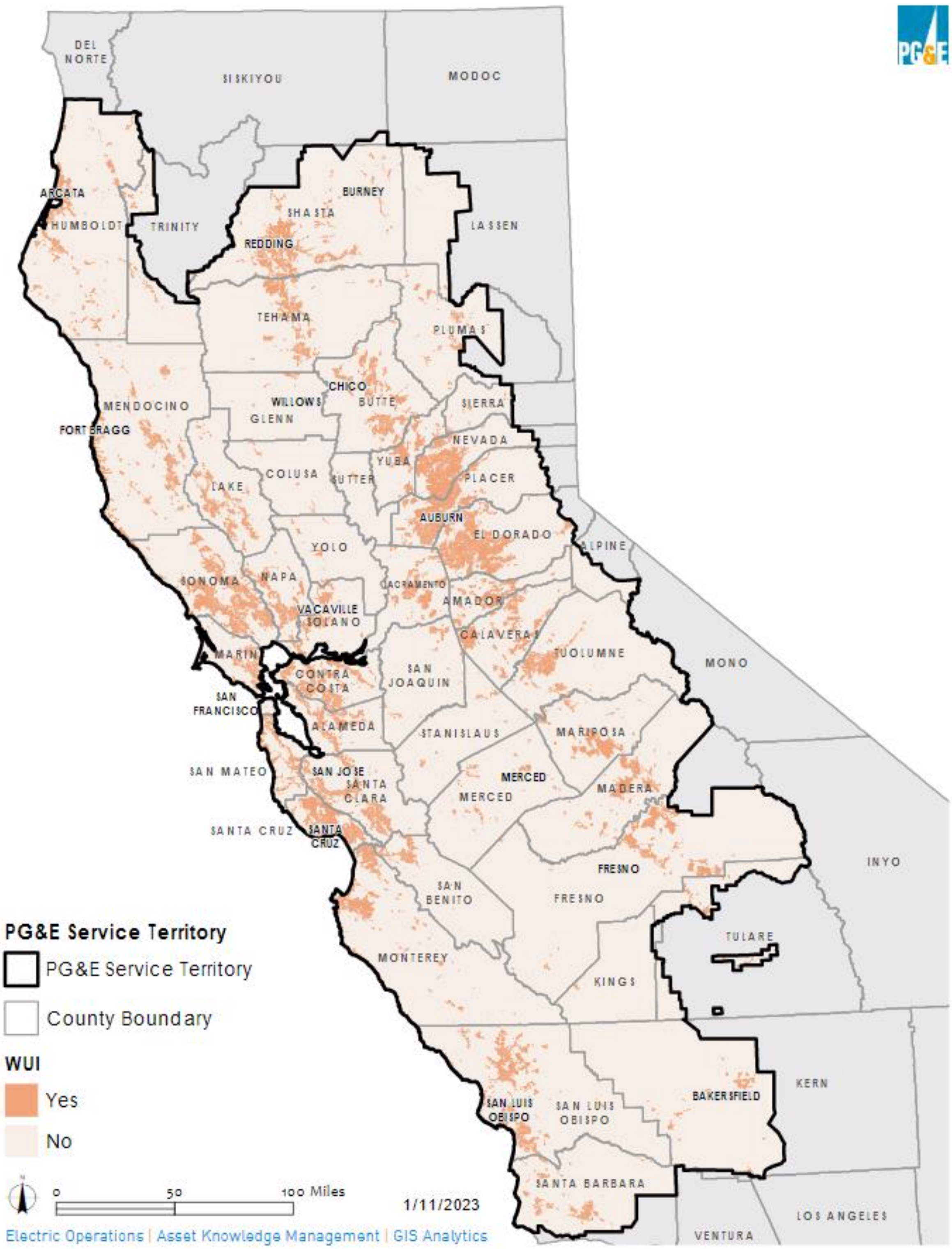
The annual number of circuit miles in the WUI is calculated by PG&E geospatial overlay/intersect of overhead distribution and transmission circuits within WUI polygons and calculation of total circuit lengths in miles within the WUI. The sources of data used in the calculation of this information include the University of Wisconsin Madison WUI GIS data layer and PG&E's GIS data layer. The annual number of customers in the WUI is calculated by PG&E geospatial overlay of transformer locations as a proxy for the customer locations and summing up the number of service points associated with each transformer to obtain total customer count within the WUI. The sources of data used in the calculation of this information include University of Wisconsin-Madison WUI GIS data layer provided by the University of Wisconsin-Madison SILVIS Lab, available here: http://silvis.forest.wisc.edu/data/wui-change-2020/ which shows the WUI areas within California as of 2020.

Table PG&E-5.4.2-1 and Figure PG&E-5.4.2-1 below show the square miles in our service territory that correspond to the population density for WUI customers.

TABLE PG&E-5.4.2-1:
SQUARE MILES IN PG&E'S SERVICE TERRITORY
CORRESPONDING TO POPULATION DENSITY OF WUI
(SUM OF SQUARE MILES)

Sum of Sq. Mi.	
Non-WUI	65,474.39
WUI	6,257.65

FIGURE PG&E-5.4.2-1:
POPULATION DENSITY MAP OF WILDLAND URBAN INTERFACE



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

5.4.3 Communities at Risk From Wildfire

In this section of the WMP, electrical corporation must provide a high-level overview of communities at risk from wildfire as defined by the electrical corporation (e.g., within the HFTD and HFRA). This includes an overview of individuals at risk, AFN customers, social vulnerability, and communities vulnerable because of single access/egress conditions within its service territory. Detailed instructions are provided below.

5.4.3.1 Individuals at Risk From Wildfire

The electrical corporation must provide a brief narrative (one to two paragraphs) describing the total number of people and distribution of people at risk from wildfire across its service territory.

PG&E estimates that approximately 1.4 million people live in HFTD areas in our service territory. This estimate was generated by selecting 2020 census blocks that have their central point within the HFTD. Those selected blocks were then broken out by county, and the sum of population per county is listed in Table PG&E-5.4.3-1 below. Only counties within the PG&E service territory are represented.

The population distribution across HFTD areas has several high and low population areas. Shasta County to the far north, El Dorado, Nevada, Placer, and Tuolumne counties in the east, and the greater San Francisco Bay Area are centers for high population within PG&E's service territory. PG&E estimates that Alpine, Colusa, Glenn, San Benito, Sierra, Stanislaus, and Yolo counties all have HFTD populations of fewer than 3,616 people. For a detailed map of population distribution, please see Appendix C.

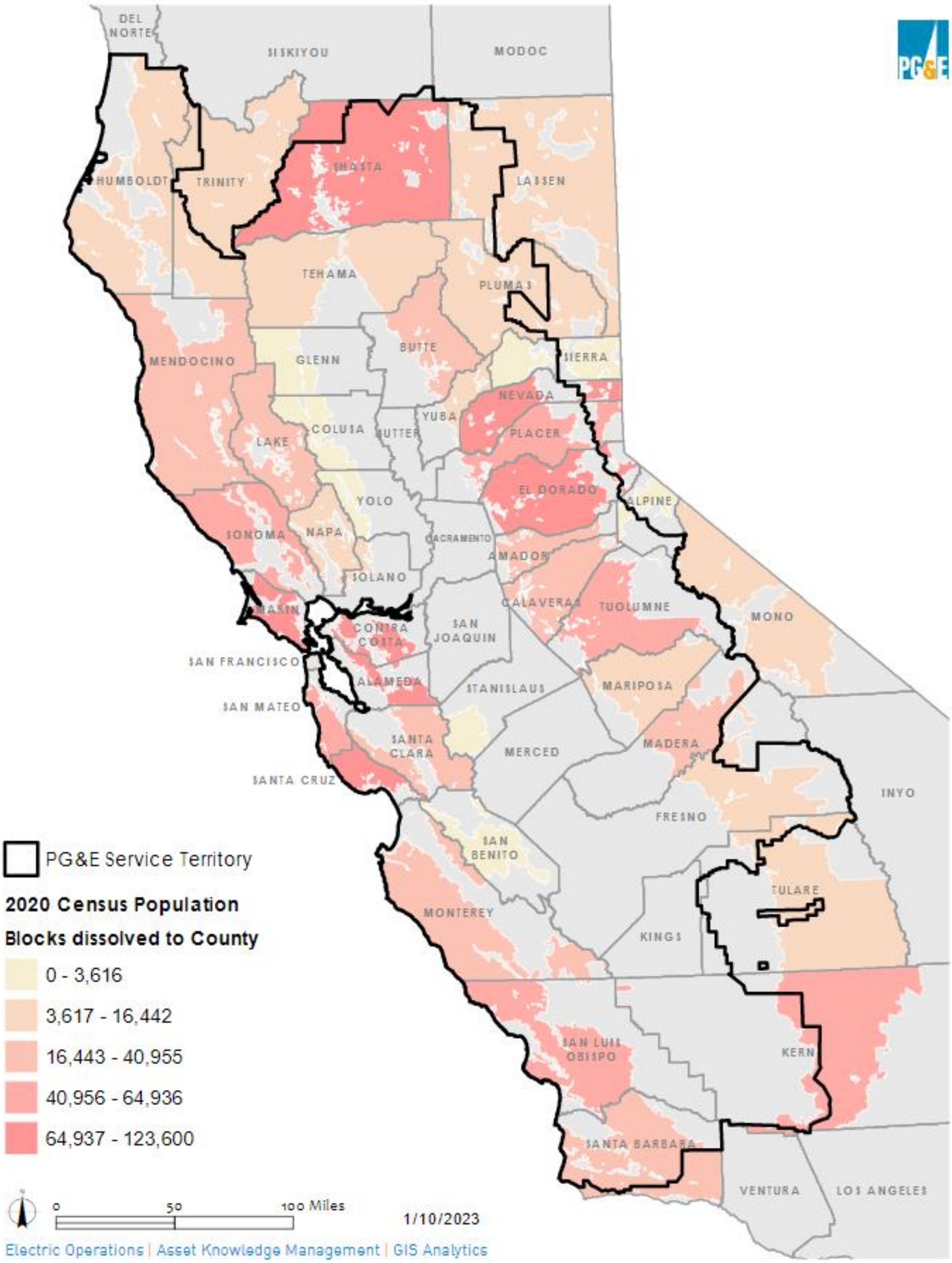
TABLE PG&E-5.4.3-1:
DISTRIBUTION OF PEOPLE AT RISK IN PG&E'S SERVICE TERRITORY

County Name	Population Count in HFTD
Alameda County	87,896
Alpine County	919
Amador County	25,034
Butte County	31,715
Calaveras County	31,037
Colusa County	307
Contra Costa County	87,012
El Dorado County	123,600
Fresno County	15,989
Glenn County	398
Humboldt County	16,442
Kern County	53,662
Lake County	31,287
Lassen County	10,090
Madera County	25,566
Marin County	90,513
Mariposa County	15,794
Mendocino County	40,955
Merced County	–
Mono County	9,964
Monterey County	33,692
Napa County	14,373
Nevada County	74,324
Placer County	64,936
Plumas County	11,032
San Benito County	3,616
San Joaquin County	3
San Luis Obispo County	56,252
San Mateo County	48,109
Santa Barbara County	39,292
Santa Clara County	39,195
Santa Cruz County	73,310
Shasta County	76,277
Sierra County	2,167

TABLE PG&E-5.4.3-1:
DISTRIBUTION OF PEOPLE AT RISK IN PG&E'S SERVICE TERRITORY
(CONTINUED)

County Name	Population Count in HFTD
Solano County	9,006
Sonoma County	55,592
Stanislaus County	1,701
Tehama County	15,309
Trinity County	13,382
Tulare County	10,415
Tuolumne County	45,570
Yolo County	486
Yuba County	9,267
Total	1,395,486

FIGURE PG&E-5.4.3-1:
2020 CENSUS POPULATION



5.4.3.2 Social Vulnerability and Exposure to Electrical Corporation Wildfire Risk

The electrical corporation must provide a brief narrative describing the intersection of social vulnerability and community exposure to electrical corporation wildfire risk across its service territory. This intersection is defined as census tracts that: (1) exceed the 70th percentile according to the Social Vulnerability Index (SVI) or have a median household income of less than 80 percent of the state median, and (2) exceed the 85th percentile in wildfire consequence risk according to the electrical corporation's risk assessment(s).[62]

For SVI, the electrical corporation must use the most up-to-date version of Centers for Disease Control and Prevention/Agency for Toxic Substances and Disease Registry's SVI dataset (Year = 2018;[63] *Geography = California; Geography Type = Census Tracts).*[64]

In addition, the electrical corporation must provide a single geospatial map showing its service territory (polygon) overlaid with the distribution of the SVI and exposure intersection and urban and major roadways. Any additional maps needed to provide clarity and detail should be included in Appendix C.

Wildfire risk models assess risk spatially along PG&E's electric assets. For the purposes of work prioritization risk can be viewed at an individual location or aggregated along a length of a circuit depending on the type of mitigation being planned. The map in Figure PG&E-5.4.3-2 displays locations where wildfire risk is in the top 15 percent of PG&E's service territory for census tracts that are greater than the 70th percentile on the Social Vulnerability Index (SVI) or have a state median household income less than 80th percentile. Intersections are most dense in the Sierra Nevada foothills, the northern Coast Range, and the far north of the service territory. Lower density high-risk areas exist throughout the service territory. Figure PG&E-5.4.3-2 below shows the SVI clipped to the 85th percentile of wildfire consequence risk.

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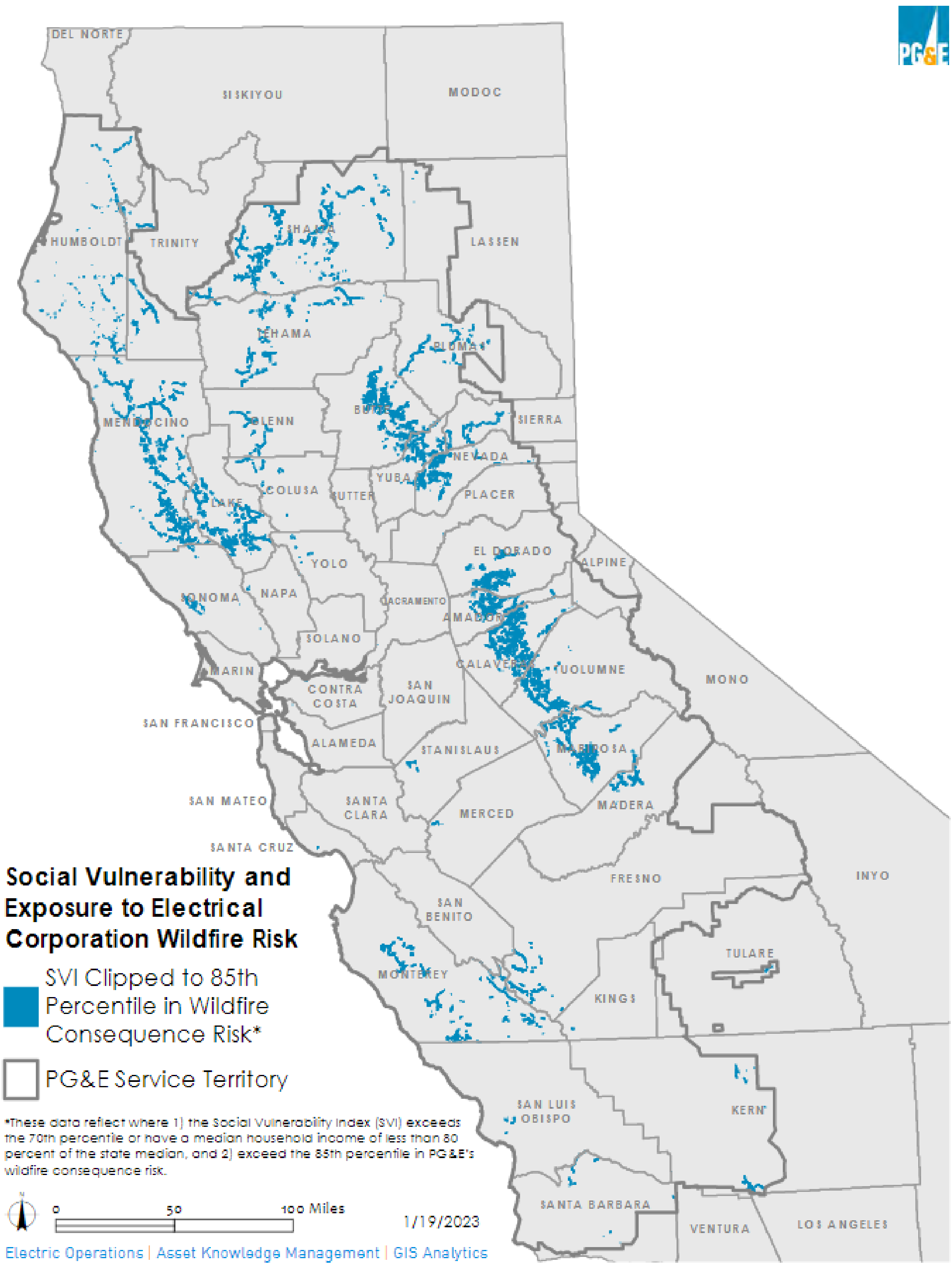
62 These criteria are derived from California Governor's Office of Emergency Services, Recovery Division, Hazard Mitigation Assistance Branch's Multiple Hazards and Social Vulnerability Analysis, dated January 18, 2022, available at: <https://www.caloes.ca.gov/wp-content/uploads/Recovery/Documents/Socially-Vulnerable-and-High-Hazard-Risk-Community-Criteria.-Methodology.pdf>, accessed January 26, 2023; see also, Hazard Exposure and Social Vulnerability Heat Map, available at: <https://calema.maps.arcgis.com/apps/dashboards/3c78aea361be4ea8a21b22b30e613d6e>, accessed January 26, 2023.

63 As of the publishing of the Guidelines, 2018 was the most recent version of the dataset. Electrical corporations must use the most up-to-date version of the dataset. (WMP Guidelines, *supra*, p. 28).

64 CDC/ATSDR SVI Data and Documentation Download, available at: <https://www.atsdr.cdc.gov/placeandhealth/svi/data_documentation_download.html>, accessed January 26, 2023.

FIGURE PG&E-5.4.3-2:
EXPOSURE AND SOCIAL VULNERABILITY MAP



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

5.4.3.3 Sub-Divisions With Limited Egress or No Secondary Egress

The electrical corporation must provide a brief narrative overview (one to two paragraphs) describing sub-divisions with limited egress or no secondary egress, per CAL FIRE data,[65] *across the electrical corporation's service territory.*

As required by the General Instructions of the Technical Guidelines, we formally requested this information from CAL FIRE in December 2022 and are awaiting a response. This information is not available from any other source nor is there a proxy. The March 6, 2023 Pre-Determination of Completeness letter from Energy Safety directed PG&E to request this information again from a specific individual at CAL FIRE and provide it when received. In response to this direction, PG&E made this request from the identified individual, and we will provide the information when it is received. PG&E does participate in the Energy Safety-led Risk Model Working Group where egress has been discussed as a topic requiring deeper discussion in conjunction with state agencies. At present, this working session is scheduled for mid-2023.

AB 2911 (2018) amended the California Public Resource Code 4290.5 that requires CAL FIRE to identify subdivisions with greater than 30 housing units located in the State Responsibility Area (SRA) or a Very High Fire Hazard Severity Zones (VHFSZ) without a secondary means of population egress. CAL FIRE has identified 917 subdivisions inside of PG&E's service territory that meet the scope of AB 2911 and has begun surveying them to assess secondary egress and limited access. These subdivisions are distributed across the entire SRA and VHFSZ area of the service territory. At the time of this writing, 496 surveys have been completed. Including subdivisions where surveys have not been completed, 522 do not have a secondary egress, 62 have limited access, and 41 have both limited access and no secondary egress. 21 subdivisions have secondary egress and no access limits per CAL FIRE's survey results. PG&E downloaded the map of Communities Vulnerable due to Access/Egress Constraints (Polygon) across PG&E Service Territory based on CAL FIRE data,[66] see Figure PG&E-5.4.3-3 below. Figure PG&E-5.4.3-3 below shows the locations of subdivisions in the SRA or VHFSZ that meet the assessment criteria of AB 2911. Additional information about each subdivision is available at the CAL FIRE site.

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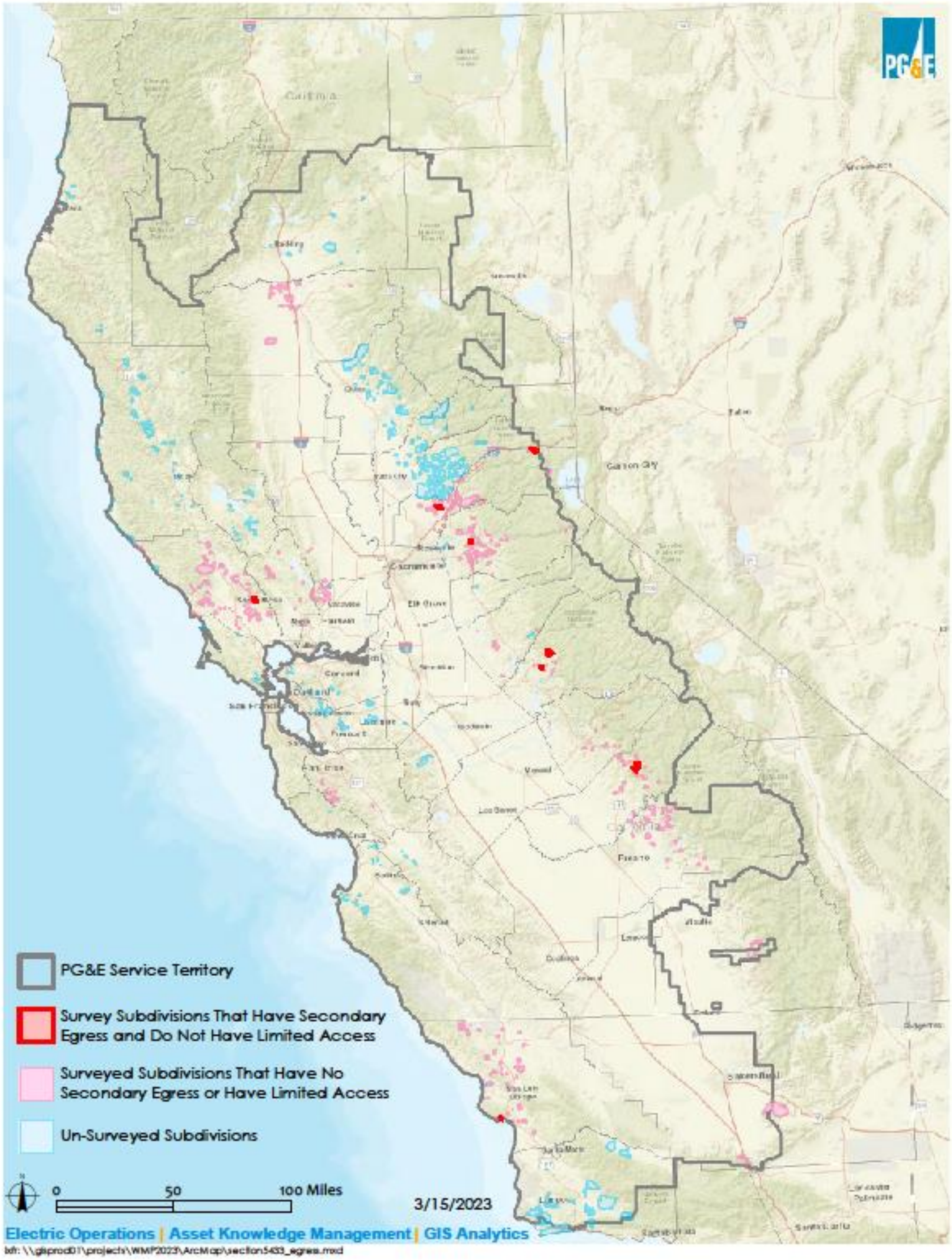
65 See, Board of Forestry and Fire Protection Subdivision Review Program, available at: <https://bof.fire.ca.gov/projects-and-programs/subdivision-review-program/>, accessed January 16, 2023.

66 The source data for this map is publicly available from the CAL FIRE and the spatial data can be downloaded at: https://calfireforestry.maps.arcgis.com/apps/webappviewer/index.html?id=a045e9e9c01c4dd7abdf14ad30646eaf.

FIGURE PG&E-5.4.3-3:
SUBDIVISIONS WITH LIMITED EGRESS OR NO SECONDARY EGRESS



5.4.4 Critical Facilities and Infrastructure at Risk From Wildfire

The electrical corporation must provide a brief narrative describing the distribution of critical facilities and infrastructure located in the HFTD/HFRA across its service territory. Critical facilities and infrastructure are defined in Appendix A.

As defined in WMP Guidelines Appendix A, critical facilities and infrastructure are essential to public safety and require additional assistance and advance planning to ensure resiliency during PSPS events. PG&E serves over 9,500 critical facility and infrastructure (CFI) customers within the Tier 2 and Tier 3 HFTD spanning across 47 counties throughout PG&E's service territory (please refer to our quarterly submission for exact CFI counts). The CFI designation process is outlined in the PSPS Pre-Season Report Section III Critical Facilities and Infrastructure Plan.

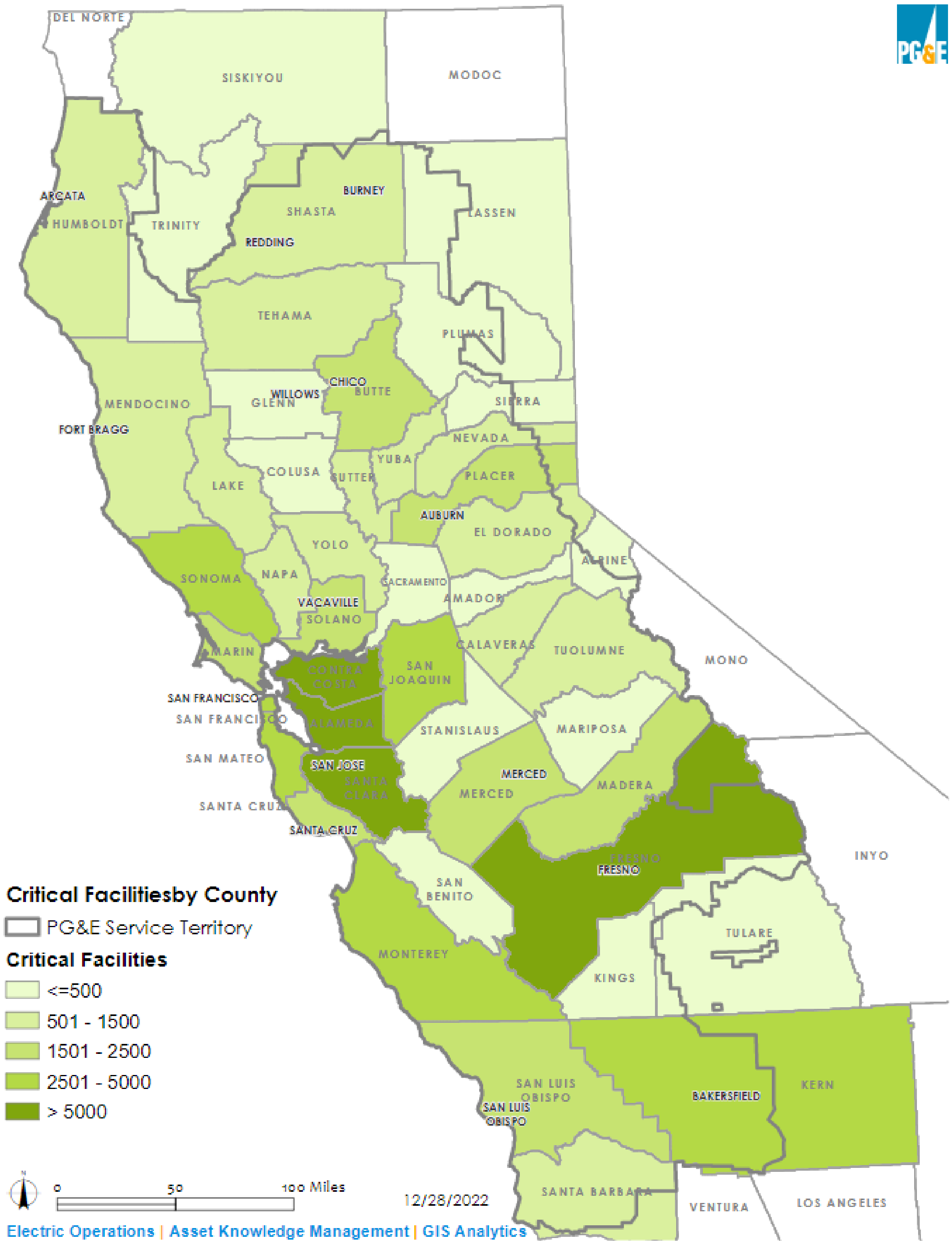
Table PG&E-5.4.4-1 below shows the count of CFI customers by Tier 3, Tier 2, and non-HFTD, and Figure PG&E-5.4.4-1 below shows the critical facilities count by county.

TABLE PG&E-5.4.4-1:
PG&E'S CFI CUSTOMER COUNTY BY TIER 3, TIER 2, AND NON-HFTD

HFTD Class	Count
Tier 3	3,462
Tier 2	7,455
Non-HFTD	74,083
Total	85,000

Note: Please refer to the Quarterly Spatial Report for additional data on Critical Facilities.

FIGURE PG&E-5.4.4-1:
CRITICAL FACILITIES COUNT BY COUNTY



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

5.4.5 Environmental Compliance and Permitting

In this section, the electrical corporation must provide an overview of its compliance with applicable environmental laws, regulations, and permitting requirements related to Vegetation Management (VM). This overview must include:

- *A description of the procedures/processes to ensure compliance with relevant environmental laws, regulations, and permitting requirements before and during WMP implementation. The process or procedure should include when consultation with;*
- *Roadblocks the electrical corporation has encountered related to environmental laws, regulations, and permitting requirements related to VM and how the electrical corporation has addressed the roadblock; and*
- *Any changes to the initiative since the last WMP submission and a brief explanation as to why those changes were made. Include any planned improvements or updates to the initiative and timeline for implementation.*

The electrical corporation must also provide a table (Table 5-6 provides an example) of potentially relevant state and federal agencies that may be responsible for discretionary approval of activities described in WMPs and the relevant environmental laws, regulations, and permitting requirements. If this table extends past two pages, provide the required information in an appendix.

**TABLE 5-6:
RELEVANT STATE AND FEDERAL ENVIRONMENTAL LAWS, REGULATIONS, AND PERMITTING REQUIREMENTS FOR IMPLEMENTING THE WMP**

Environmental Law, Regulation, or Permit	Responsible Permittee/Agency
Clean Water Act	California Regional Water Board
Coastal Act	California Coastal Commission
Endangered Species Act and Streambed Alteration	California Department of Fish and Game.

PG&E's Environmental Release to Construction for Environmental Evaluations Standard (ENV-10002S)[67] requires all employees and contractors to submit an Environmental Release to Construction (ERTC) prior to the implementation of operation and maintenance or construction activities. The ERTC catalogs all activity-specific permits, agreements, authorizations, and other environmental requirements and is used to ensure PG&E remains compliant with applicable federal, state, and local laws and internal environmental guidance.

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67 Appendix E.

When conducting VM activities, PG&E employees and contractors must adhere to PG&E's Best Management Practices (BMP) where practicable. BMPs are considered practicable where physically possible and not conflicting with other regulatory obligations or safety considerations (GO 95 Rule 35 and Public Resources Codes 4292 and 4293) or emergency response situations. These BMPs are designed to ensure that PG&E VM activities are performed in an environmentally sensitive manner to minimize environmental impacts. Under the guidance of BMPs, VM employees and contractors must conduct ongoing training related to environmental laws and procedures. VM employees and Contractors performing VM activities must comply with these laws and procedures to minimize or avoid effects on natural resources during work activities. Please refer to the PG&E BMPs (TD-7102P-01-JA01) in Appendix E for more information.

PG&E has made several changes related to environmental compliance and permitting. We identified opportunities to address challenges, feedback, and roadblocks through efforts described below.

To address expired authorizations PG&E collaborated with the Pacific Southwest Region (Region 5) of the USFS to establish 30-year Master Permits and Easements and an associated operations and maintenance (O&M) Plan on National Forest System lands in California (the Plan). The Plan, which was executed in February 2019, impacts approximately 420 authorizations administered by the USFS in the El Dorado, Lassen, Los Padres, Mendocino, Plumas, Sequoia, Shasta-Trinity, Sierra, Six Rivers, Stanislaus, and Tahoe National Forests. This action consolidated and combined existing land authorizations into 21 master permits and easements. It addresses both electric distribution and transmission assets. The Plan authorizes routine operation and maintenance work (i.e., performing minor repairs to poles and fiber optic line; completing VM services such as line clearance; replacing existing poles and towers, felling hazard trees, replacing or pulling new conductors; and performing emergency work to address immediate threats).

During 2022, PG&E received feedback from the eleven forests that O&M work, including VM, conducted under the Plan, was more streamlined and they were appreciative of the enhanced communication. PG&E conducted 3-hour annual meetings with each of the forests individually in addition to numerous other check-ins throughout the year. PG&E also conducted Stewardship Planning meetings with the four forest zones to discuss improving wood and debris management protocol. We also continued to meet with the Regional Office bi-weekly throughout 2022.

Like our effort with the USFS, PG&E is in contact with the Department of the Interior (DOI), specifically National Park Service (NPS) and Bureau of Land Management (BLM). The goal is to establish multi-year Master Right-of-Way (ROW) Permits and Grants and Master O&M Plans with each of the agencies. PG&E is coordinating with the DOI to finalize long-term Master ROW Permits and Grants and Master O&M Plans to help us with wildfire prevention.

NPS Special Use Permits (SUP): In April 2019, PG&E requested authorization to conduct wildfire prevention activities on NPS-managed land in an expedited manner. In response to PG&E's request for a short-term renewable permit from NPS, the NPS Pacific West Regional Office Park units worked with PG&E to develop 1-year SUPs for each park. The issuing permits are for the Yosemite, Redwood, Pinnacles, Point Reyes, Kings Canyon, and Lassen Volcanic national parks, as well as the Whiskeytown National Recreation Area and the Eugene O'Neill National Historic Site. These permits went into effect on February 1, 2020, and were renewed in February 2021 and again in February 2022. The permits apply to all PG&E electric facilities on NPS managed land, regardless of whether the facilities have, or need, an easement or ROW. The permits allow PG&E to perform work such as pole replacements, tree removal and pruning, VM inspections, and road maintenance and repairs. The 1-year permits are expected to be renewed each year until a multi-year Master ROW Permit and Master O&M Plan is negotiated with the NPS.

We continued to meet with the Regional Office monthly throughout 2022. We kicked off long-term programmatic agreement and executed a project agreement, data sharing agreement, and cost recovery agreement to outline milestones and schedule for completing the long-term Master ROW Permit and Master O&M Plan. The schedule to complete the effort is December 2025.

In December 2020, the BLM California State Office issued a Wildfire Instruction Memorandum (IM), which establishes policy regarding routine O&M activities on electric utilities ROW to reduce the risk of wildfire. Under this directive, electric transmission and distribution facility ROW holders have the authority to conduct routine O&M activities within their ROW to reduce wildfire risk. The IM was renewed in 2021 for 5 years. PG&E created and implemented a streamlined process to ensure compliance with the IM.

PG&E began working with a BLM pilot team out of Bakersfield to establish 30-year Master ROW Grants and associated O&M Plan. The expected completion date is December 2023 for the pilot office and December 2024 for the remaining field offices. We also continued to meet with the State Office quarterly throughout 2022.

In April 2020, the California Department of Parks and Recreation entered a Near-Term Process (NTP) with PG&E, which establishes a formal review and approval process regarding routine O&M activities on electric and gas utilities ROW to reduce the risk of wildfire. Under the NTP, PG&E can release routine O&M activity within 14 days after submission of a complete notification to State Parks where authorized ROWs are in place.

PG&E met with headquarters monthly and had numerous check-ins with State Parks throughout 2022, in addition to a 3-hour annual meeting. We received feedback from State Parks that the O&M work, including VM, under the NTP has improved, citing enhanced communication.

PG&E continues to use our Habitat Conservation Plans (HCP) to protect threatened and federally designated endangered species and their habitats, while maintaining and operating our gas and electric infrastructure. Our entire service territory now has federal coverage for endangered species most likely to be found near our gas and electric infrastructure. This includes our San Francisco Bay Area HCP, which protects 18 wildlife species and 13 plant species throughout the nine Bay Area counties. Our San Joaquin Valley HCP protects 23 wildlife and 42 plant species within nine counties of the San Joaquin Valley. Our Multiple-Region HCP protects 24 animal and 12 plant species, 35 of which are listed as threatened or endangered under the Endangered Species Act.

In addition to the HCPs, PG&E is working with the California Department of Fish and Wildlife on 30-year programmatic permits for the protection of California designated endangered species. These permits will provide coverage for O&M activities within the Bay Area, Mojave, and select regions in the Central Valley and Central Coast.

PACIFIC GAS AND ELECTRIC COMPANY

2023-2025 WILDFIRE MITIGATION PLAN

SECTION 6

RISK METHODOLOGY AND ASSESSMENT

6. 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). This information is intended to provide the reader with a technical understanding of the foundation for the electrical corporation's wildfire mitigation strategy for its Base WMP. Sections 6.1-6.7 below provide detailed instructions.

For the 2023-2025 Base WMP, the electrical corporation does not need to have performed each calculation and analysis indicated in Sections 6.2, 6.3, and 6.6. If the electrical corporation is not performing a certain calculation or analysis, it must describe why it does not perform the calculation or analysis, 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.

6.1 Methodology

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

In this section PG&E is providing an overview of the company's approach to risk assessment and risk management. We begin at the Enterprise level with the Enterprise Risk Management Process that we use to identify and rank risk, which is followed by the Electric Operations (EO) Risk Analysis Methodology

6.1.1 Overview

The electrical corporation must provide a brief narrative describing its methodology for quantifying its overall utility risk of wildfires and Public Safety Power Shutoff (PSPS). This methodology will help inform the development of its wildfire mitigation strategy (see Section 7). 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.

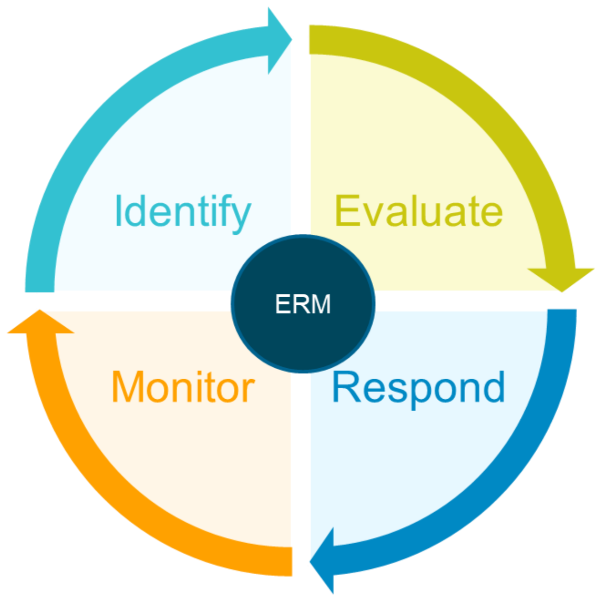
The risk assessment in this WMP is based on a quantitative risk assessment approach to determine PG&E's overall utility risk from wildfires and PSPS for our service territory. The intent of performing this risk analysis is to:

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

- Use this understanding of risk to inform the development and prioritization of a comprehensive wildfire mitigation strategy in Section 7 that achieves the goals and plan objectives stated in Section 4.1 and Section 4.2.

PG&E's methodology of assessing overall utility risk of wildfires and PSPS includes four major steps: (1) Risk Identification; (2) Risk Evaluation and Quantification; (3) Risk Response; and (4) Risk Monitoring and Reporting. Figure PG&E-6.1.1-1 below is an overview of PG&E's risk management process.

FIGURE PG&E-6.1.1-1:
OVERVIEW OF PG&E'S RISK MANAGEMENT PROCESS



Risk Identification

The Risk Identification process involves the EO Risk Team, risk owners, and Subject Matter Experts (SME) who together identify and evaluate EO risks. Risks that are identified by the EO Risk Team are reviewed by the EO Risk and Compliance Committee (RCC). Ultimately, the RCC approves the list of risks that are included on the EO Risk Register. The risks that are on the EO-owned Risk Register are the same as the EO risks that are on the Corporate Risk Register managed by Enterprise and Operational Risk Management.

Risk Evaluation and Quantification

PG&E uses the bow-tie methodology to evaluate risk events, consistent with the Safety Model and Assessment Proceeding framework. The bow-ties illustrating the EO risk are provided in each risk section below. The bow-tie methodology provides: (1) a high-level visual summary of the risk event (the center of the bow-tie); (2) a detailed process for presenting the risk drivers, the likelihood or frequency of the risk event (the left side of the bow-tie); (3) the potential consequences of the risk event (the right side of the bow-tie), and the score for the assessed risk (the bottom, center of the bow-tie). Developing the bow-tie methodology includes defining exposure, drivers, tranches, 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 is supported by records associated with outages, ignitions, and other failure mode data.

- Risk tranches include a group of assets, a geographic region, or other grouping that is intended to have 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. Exposure to the risk 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 High Fire Threat District (HFTD) 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 determine the likelihood or frequency of a risk event. Risk drivers include external events (such as vegetation contact driver) 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 sub-driver and 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 would 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,[68] Customer Minutes Interrupted (CMI) and dollars, respectively, then aggregated into a single Consequence of a Risk Event (CoRE) value using PG&E's Multi-Attribute Value Function (MAVF).

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 then 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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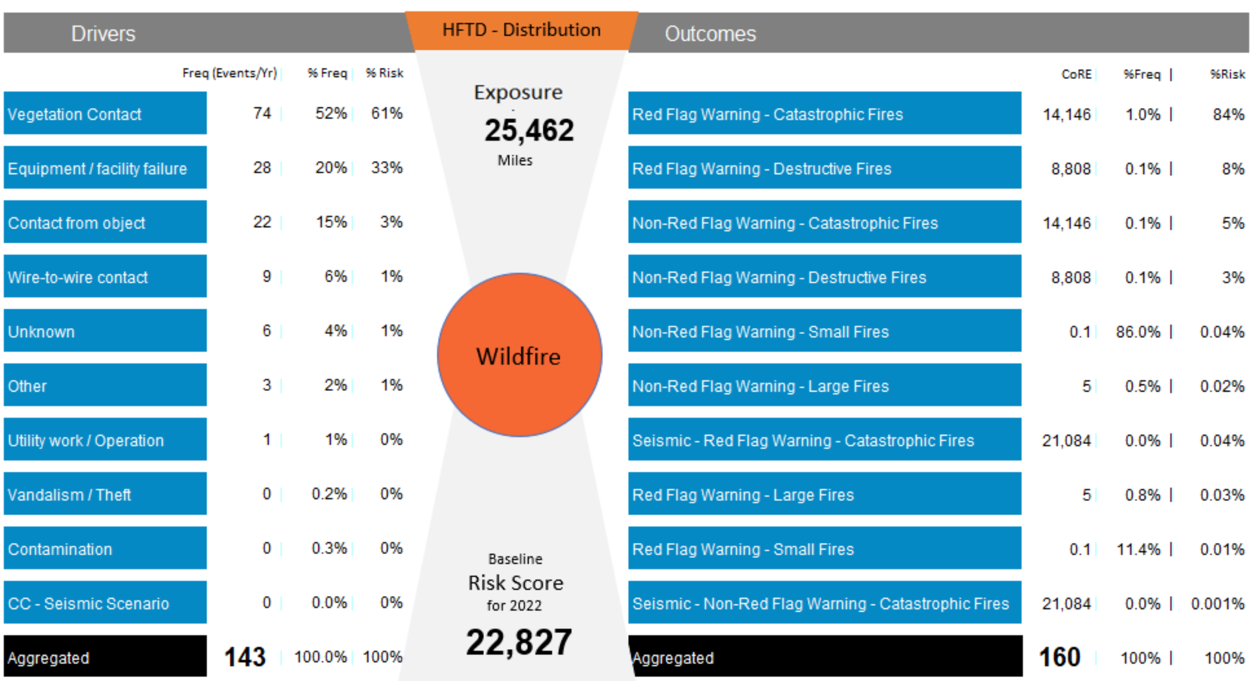
68 Equivalent fatalities defined as the sum of number of fatalities and 0.25 times the number of serious injuries.

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

FIGURE PG&E-6.1.1-2:
RISK BOW-TIE FOR WILDFIRE RISK, TRANSMISSION AND DISTRIBUTION SYSTEM

FIGURE PG&E 6.1.1-3:
RISK BOW-TIE FOR WILDFIRE RISK, HFTD DISTRIBUTION SYSTEM



Risk Response

The EO Risk Team works with SMEs to identify appropriate controls and mitigations to manage the risk (see Section 7). Control programs are ongoing activities that maintain the existing level of risk. Mitigation programs are activities designed to reduce the level of risk. Control and mitigation programs are associated with risk drivers, risk consequences, and/or risk tranches to accurately quantify the benefits of the program. Mitigation and control programs are assessed based on how much of the tranche exposure is affected (i.e., scope of mitigation), the impact on specific driver/sub-driver frequencies over time, and the impact on the consequence of specific attribute.

Risk Monitoring and Reporting

EO reports on the status of its risks and the performance of its risk response programs through forums such as the RCC, the Wildfire Weekly Operating Review, and the Wildfire Risk Governance Steering Committee. Based on the performance of the risk and response programs, PG&E may accelerate or adjust our responses to better manage the risk. As part of the risk monitoring process, we continue to look for opportunities to improve our risk modeling.

6.1.2 Summary of Risk Models

In this section, the electrical corporation must summarize the calculation approach for each risk and risk component identified in Section 6.2.1. 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 6.3;*
- *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 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 Outputs: List of outputs calculated for the risk or risk component;*
- *Units: List of the units associated with the key outputs; and*

Table 6-1 provides a template for the information. The electrical corporation must provide a summary of each model in Appendix B.

Table 6-1 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 6.3 below.

TABLE 6-1:
PG&E RISK MODELS

ID	Risk Component	Design Scenario	Key Inputs	Source of Inputs	Key Outputs	Units
UR	Overall Utility Risk	PL1	PSPS Risk and Ignition/Wildfire Risk		Circuit Segment Level Risk	MAVF
WFR	Ignition/Wildfire Risk (WDRM/WTRM)	PL1	Ignition Probability Ignition Consequence	Ignition Likelihood Ignition/Wildfire Consequence	Pixel (100m x 100m) Risk Circuit Segment Risk	MAVF
PSPS R	PSPS Risk	PL1	PSPS Consequence PSPS Likelihood	Historical Meteorology Data	SPID Risk Circuit segment Risk Circuit Risk	MAVF
PI	Ignition Likelihood	PL1	Equipment subset ignition probability Contact from object subset ignition probability	Equipment Likelihood of Ignition Contact from Object Likelihood of Ignition	Pixel (100m x 100m) probability Circuit Segment Probability	Ignitions/year
WFC	Ignition/Wildfire Consequence	PL1	Wildfire Hazard Intensity Wildfire Exposure Potential Wildfire Vulnerability Burn Probability	Technosylva FPI VIIRS	Pixel (100m x 100m) consequence Circuit Segment consequence	MAVF
PSPS C	PSPS Consequence	PL1	PSPS event data Customer data	Historical Meteorology Data	SPID Consequence Circuit segment Consequence Circuit Consequence	MAVF

TABLE 6-1:
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 (see Table PG&E-6.2.1-1)	Distribution Asset Data, Historical Outages and Ignitions, PSPS Damages and Hazards, Meteorological data, National Land Cover Database, LANDFIRE surface fuels, HFTD, Vegetation LiDAR, Fire Protection Index (FPI), Real-Time Mesoscale Analysis	100m x 100m pixel Annual probability of ignition	Ignitions/year
CFOI	Contact from Object Likelihood of Ignition	PL1	Contract from object sub model (see Table PG&E-6.2.1-1)	Distribution Asset Data, Historical Outages and Ignitions, PSPS Damages and Hazards, Meteorological data, National Land Cover Database, LANDFIRE surface fuels, HFTD, Vegetation LiDAR, Fire Protection Index (FPI), Real-Time Mesoscale Analysis	100m x 100m 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

TABLE 6-1:
PG&E RISK MODELS
(CONTINUED)

ID	Risk Component	Design Scenario	Key Inputs	Source of Inputs	Key Outputs	Units
WEP	Wildfire Exposure Potential	PL1	VIIRS FPI Terrain Difficulty Index (TDI)	VIIRS FPI Technosylva	100m x 100m pixel destructive potential classification	% of days
WFV	Wildfire Vulnerability	PL1	AFN FPI	AFN FPI	Customer demographics by circuit segment	Counts/circuit segment
PSPS L	PSPS Likelihood	PL1	Historical Meteorology		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

6.2 Risk Analysis Framework

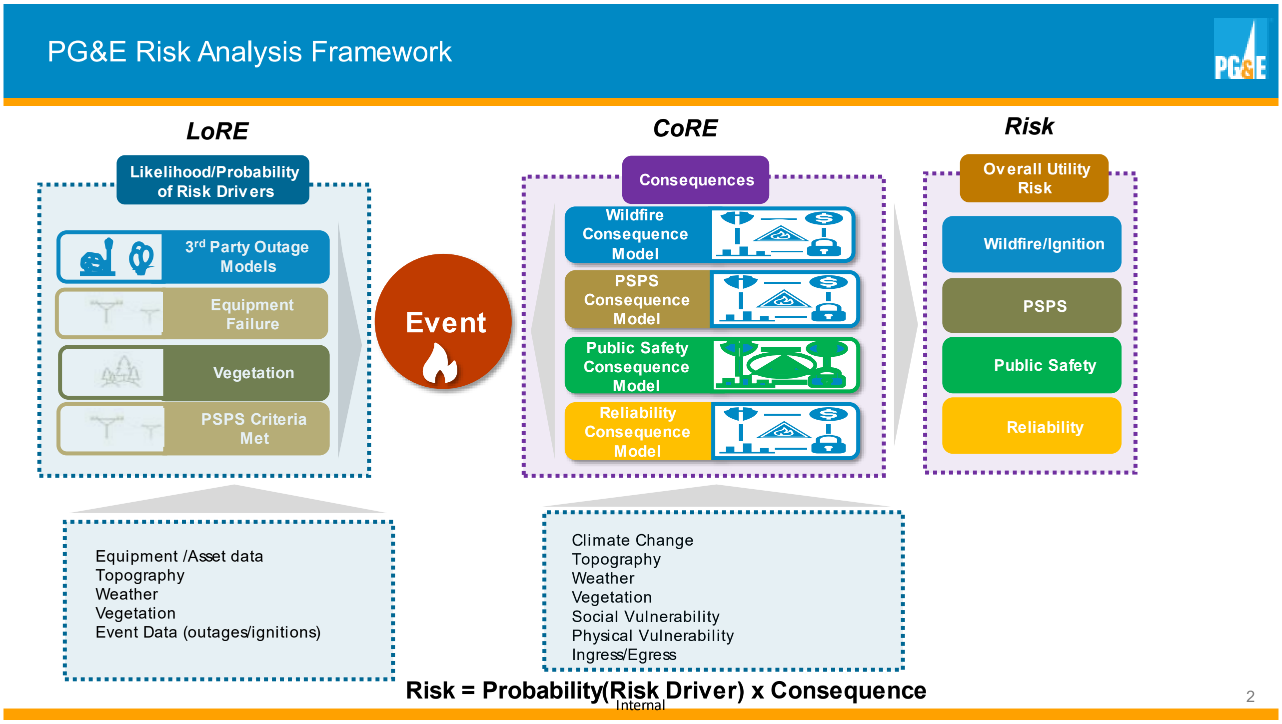
In this section of the WMP, the electrical corporation must provide a high-level overview of its risk analysis framework. This includes a summary of key modeling assumptions, input data, and modeling tools used.

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), socioeconomic factors, etc.);*
- *Physical Vulnerability (e.g., people, structures, critical facilities/infrastructure, etc.); and*
- *Coping Capacities (e.g., limited access/egress, etc.).*

PG&E's risk analysis framework (Figure PG&E-6.2-1 below) informs our risk mitigation strategy by quantifying the existing risk and the risk reduction that occurs after we implement our mitigations. The risk analysis framework in Figure PG&E-6.2-1 below draws from the risk bow-tie analysis. The bow-tie analysis identifies the risk drivers. Predictive analytical models are then developed to quantify the probability and impact (consequence) associated with each risk driver.

FIGURE PG&E-6.2-1:
PG&E'S RISK ANALYSIS FRAMEWORK



The risk analysis framework develops predictive models to represent the risk drivers across a portfolio of risks where risk is calculated as the product of the probability of an event associated with a risk driver and the potential consequences from that event.

The components of the framework are dynamic. Input data, modeling assumptions and tools are adjusted as we mature and improve our predicitive risk models.

Improving the predictive power of the risk model involves preparing and developing better input data sets, including training data and machine learning models, modeling tools and algorithms, and improving modeling assumptions.

PG&E quantifies overall utility risk based on the framework displayed in Figure PG&E-6.2-1 above where risk is the product of the probability of an event (LoRE) and the consequences of that event (CoRE). Within the probabilistic LoRE, the range of risk drivers can be represented and quantified.

For example, the probability of risk drivers related to ignitions can be individually represented in the model. These risk drivers can then be matched with corresponding consequences to represent a range of risks. As a probability, the LoRE components are produced on a range of 0 to 1. When the consequences of CoRE are calibrated within the MAVF framework, then the resulting risk values are comparable.

When the LoRE and CoRE components are represented by predictive models that quantify the probability or consequence temporally and spatially across the PG&E service territory, mitigation workplans can be developed to focus on the most effective locations for risk reduction.

This framework is employed for specific distribution and transmission LoRE models. As shown below in Figure PG&E-6.2-2 (Distribution) and Figure PG&E-6.2-3 (Transmission) the distribution and transmission wildfire risk models apply different approaches to use the input data to develop a probability model output.

FIGURE PG&E-6.2-2:
WILDFIRE DISTRIBUTION RISK ANALYSIS FRAMEWORK

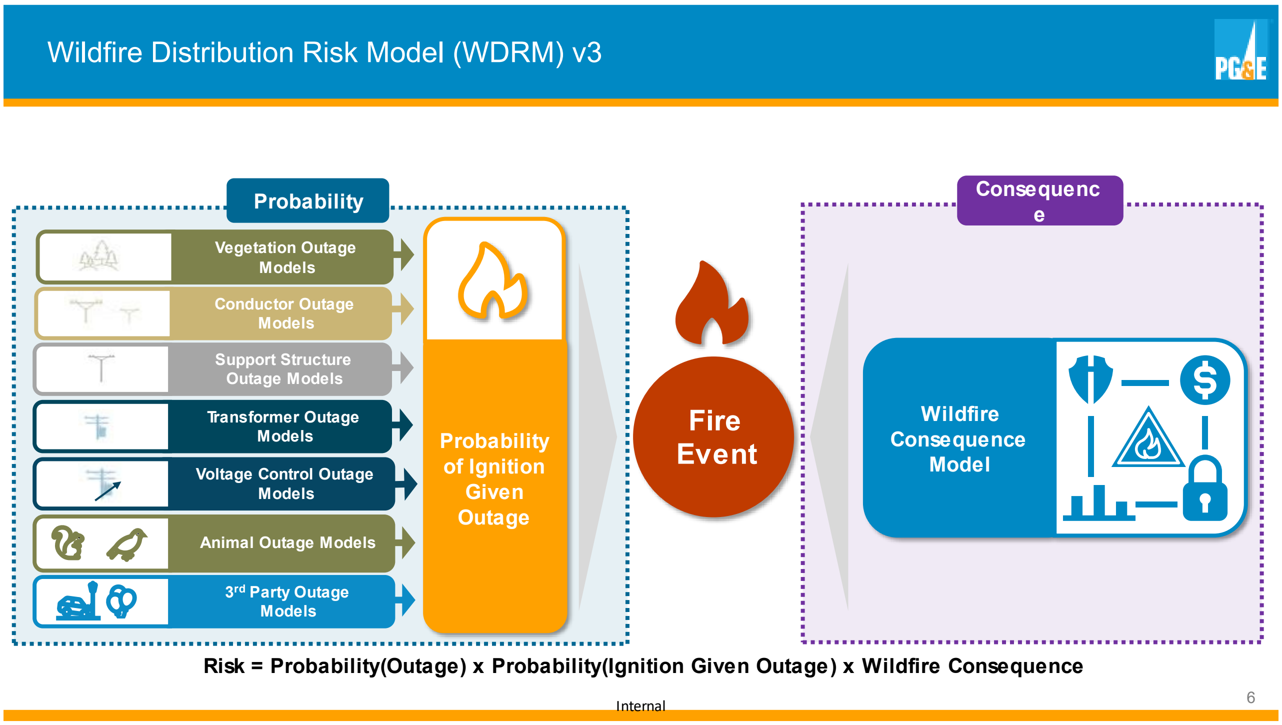
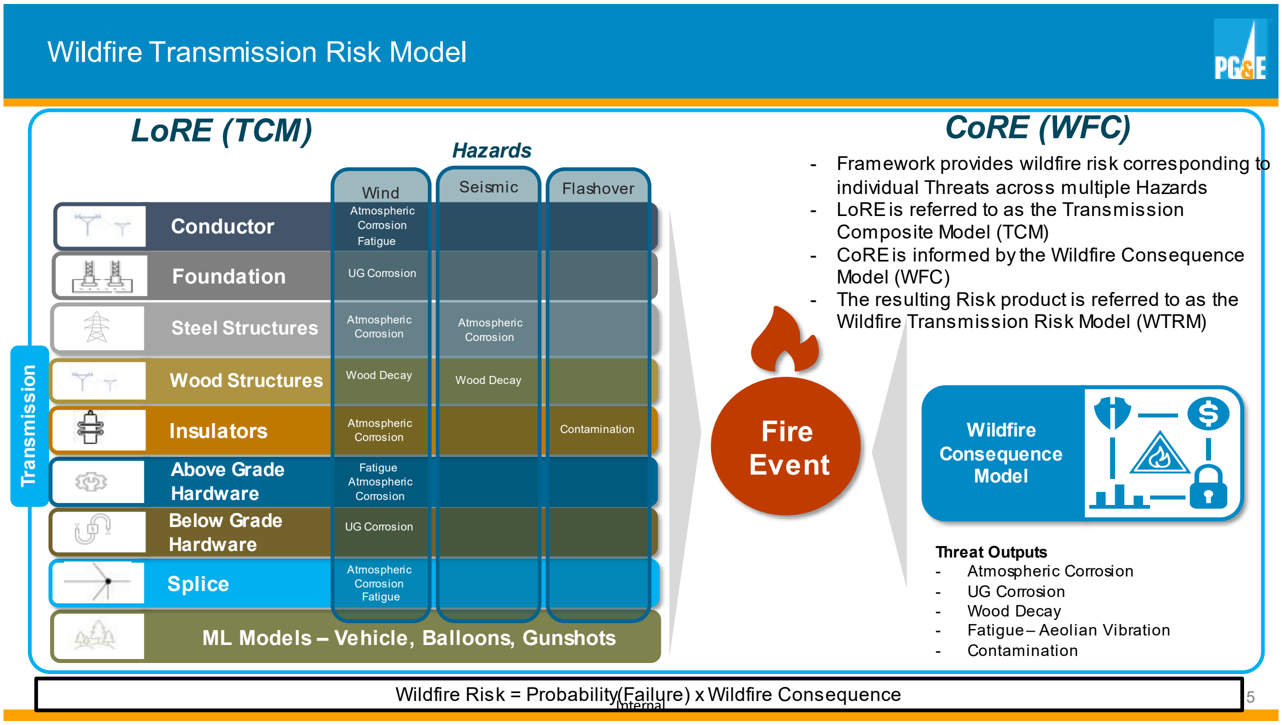


FIGURE PG&E-6.2-3:
WILDFIRE TRANSMISSION RISK ANALYSIS FRAMEWORK



Using Predictive Models: LoRE

Producing a predictive model for risk drivers involves a range of data sets. These are best categorized as data sets that represent threats and hazards:

- Threats represent degradation to the initial condition or strength of assets; and
- Hazards are forcing functions that act on the assets causing the failure.

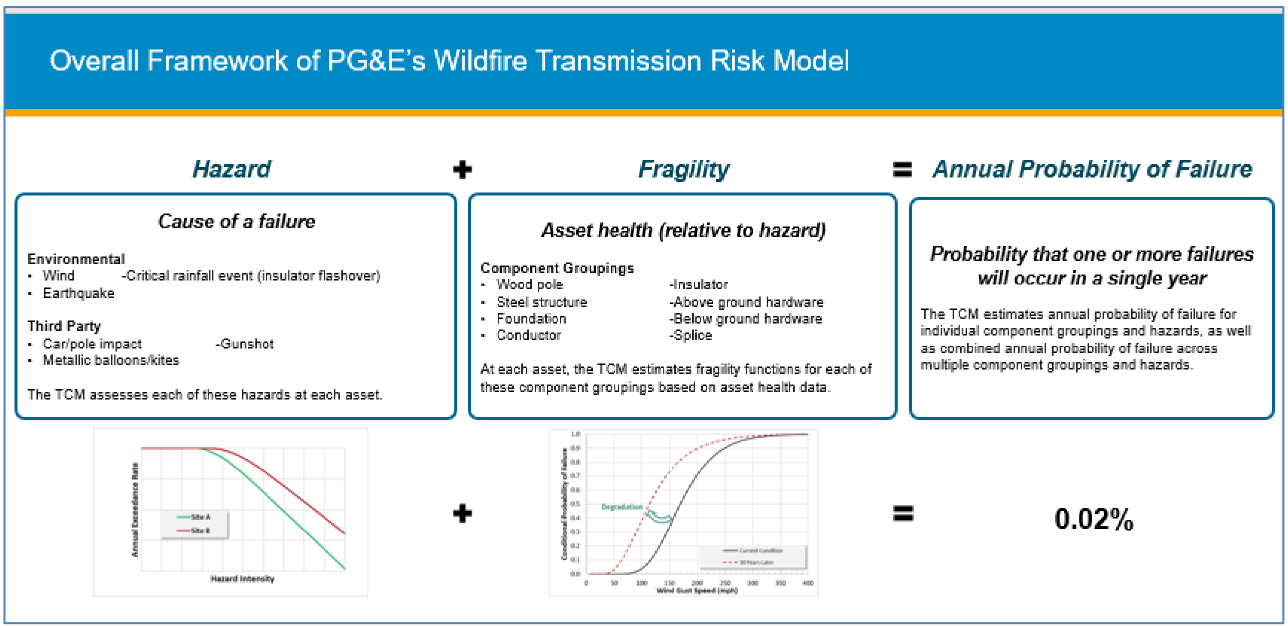
Threats impact the condition of the asset such as corrosion, wood decay, and wear. These are captured as part of the asset data as the condition of the asset. Asset data is the most important data set to represent risk and it is the area where we have the most opportunity to improve the predictive performance of our risk models. Asset data is critical to the LoRE portion of the Risk Analysis Framework, and it includes information about both the asset characteristics and information on asset failures from outage reports.

The second set of data represent hazards. Hazards represent a forcing function that cause asset failure depending on the condition of the asset. Data sets that capture the propensity of wind in the same location as an asset are an example of a hazard. Other examples are meteorology data, infrastructure such as roads, vegetation data, animal species data, and other environmental data sets.

For machine learning models, such as are used in the WDRM, both Threat and Hazard data sets are used as covariate or input data sets. For engineering models, like those used in the WTRM, the failure probability is represented by a fragility curve where the threat shifts the fragility curve, and the hazard is the force that is applied and can exceed the strength of the asset resulting in the failure.

Figure PG&E-6.2-4 below shows how Threat and Hazard combine to predict the probability of failure for a transmission asset.

FIGURE PG&E-6.2-4:
WILDFIRE TRANSMISSION RISK MODEL



Particularly for machine learning models, risk driver event data enables us to produce more granular sub-models. Due to this, both the nature and location of the failure event is needed to best represent the risk driver that is the objective function of a machine learning model.

Using Predictive Models: CoRE

The CoRE models use a range of data to assess the consequence of the predicted event from the LoRE side of the model.

For WFC, we employ different data sets, fire simulation models, and environmental data sets. To assess the potential impact of wildfire spread, PG&E leverages data sets from Technosylva's fire simulation modeling (see Section 8.3.5.1). These data sets represent the estimated acres, structures, rate of spread, flame length, or simulated fire at a given location. These simulations employ a range of environmental data such as fuel levels, moisture content, and historical meteorology data and include climate forecasts of these same data sets. These data sets are combined within a regression model with PG&E meteorological data and fire and ignition histories to represent the potential consequences of ignitions along the electric assets in PG&E's service territory.

Future improvements to WFC will account for the impacts of fire suppression on the size and extent of the fire and egress, (accounting for the capability of people to successfully move out of the path of the fire). Early development of these modeling capabilities includes demographic data such as social and physical vulnerabilities, access to transportation, and physical mobility.

Table PG&E-6.2-1 below summarizes how we address key likelihood and consequence factors in our risk models.

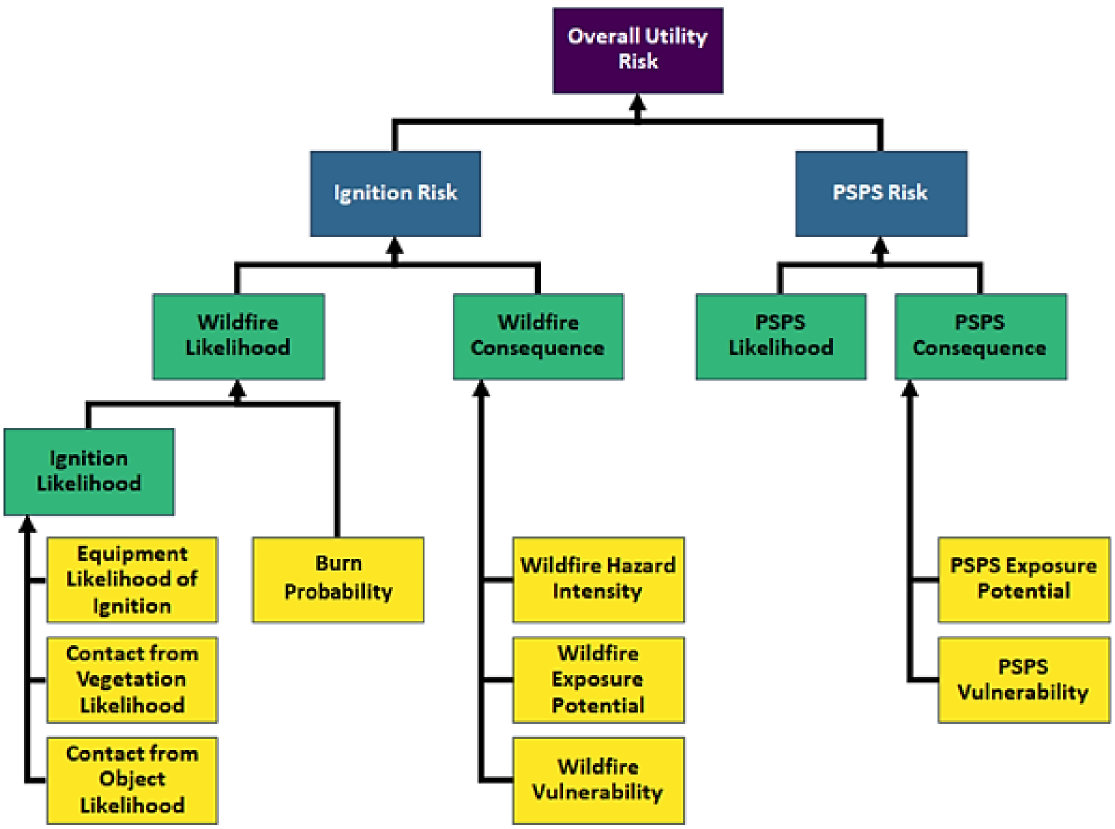
TABLE PG&E-6.2-1:
ADDRESSING KEY LIKELIHOOD AND CONSEQUENCES IN RISK MODELS

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. 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	Included in early development of updates to consequence models as a factor in effective evacuations (egress) in future models.
Physical Vulnerability	Included in early development of updates to consequence models as a factor in effective evacuations (egress) in future models.
Coping Capacities	Included in early development of updates to consequence models as a factor in effective evacuations (egress) in future models.

6.2.1 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 and PSPS events across its service territory. This includes several likelihood and consequence risk components that are aggregated based on the framework shown in Figure 6-1 below. The following paragraphs define each risk component.

**FIGURE 6-1 (EXAMPLE):
COMPOSITION OF OVERALL UTILITY RISK**



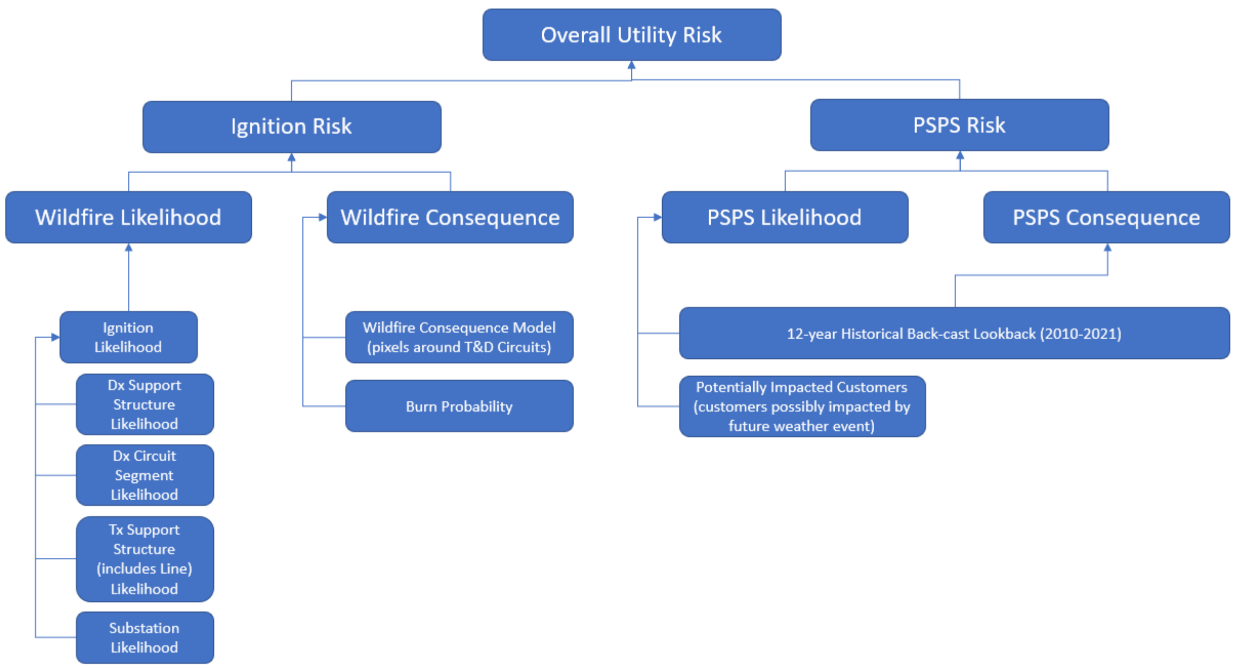
While the overall utility risk framework and associated risk components identified in Section 6.2 are the minimum requirements for determining overall utility risk, the electrical corporation may elect to include additional risk components, as needed, to better define risk for its service territory. 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 6-1), including any components beyond minimum requirements.

PG&E identifies the components of risk based on Wildfire and PSPS as required by WMP Guidelines Figure 6-1.

$$\boldsymbol{Overall\ Utility\ Risk} \quad = \boldsymbol{Ignition/Wildfire\ Risk}\ (\boldsymbol{Dx},\ \boldsymbol{Tx},\ \boldsymbol{Sub}) + \boldsymbol{PSPS\ Risk}\ (\boldsymbol{Backcast},\ \boldsymbol{PIC})$$

$$\boldsymbol{Enterprise\ Risk}(\boldsymbol{MAVF}) = (\mathbf{23,082}\ \boldsymbol{Dx} + \mathbf{772}\ \boldsymbol{Tx} + \mathbf{14}\ \boldsymbol{Sub}) + (\mathbf{2,170}) = \mathbf{26,038}$$

FIGURE 6-1:
IDENTIFICATION PG&E'S OVERALL UTILITY RISK



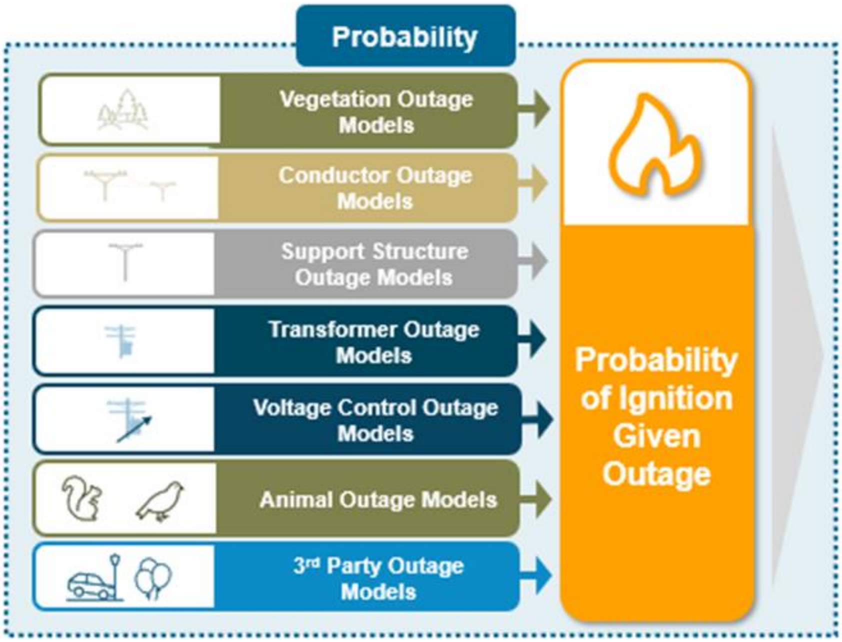
Wildfire Risk/Ignition Risk Framework

Wildfire Risk, referred to as Ignition Risk in the WMP Guidelines, is the product of the probability or likelihood of a wildfire and the consequences of that wildfire.

In modeling the wildfire causal chain of events, PG&E does not distinguish between the probability of an ignition and the probability of a wildfire. Modeling focuses on predicting the probability of a failure and then the probability that that failure will result in an ignition. The extent and impact of that ignition is then characterized by the WFC. As such burn probability is modeled as part of the wildfire consequence model and not part of the wildfire likelihood.

PG&E's risk modeling approach starts by calculating the likelihood of an individual failure (Step 1) and then the probability, or likelihood, of that event resulting in an ignition (Step 2). This 2-step process is shown in Figure PG&E-6.2.1-1 below.

FIGURE PG&E-6.2.1-1:
PROBABILITY



<u>Ignition Likelihood</u>

The ignition probability model assumes all ignitions are equal and does not distinguish among failure types. While these assumptions do not capture the potential difference in energy levels or durations for different failure types it does allow an increased sample size for developing a spatially specific model that accounts for meteorological conditions that are key factors in the development of an ignition.

<u>Event Likelihood (LoRE)</u>

To calculate the likelihood of an individual failure (Step 1) and then the probability of that event resulting in an ignition (Step 2) PG&E analyzes 17 outage types related to either environmental issues (e.g., vegetation caused outages) or equipment failures.

The first step of this two-step process is the prediction of the failure likelihood or LoRE. What follows describes the data sets for models, the inputs (or covariates) to the LoRE models, and how the WDRM v3 estimates the probability of an ignition through two modeling steps, in which the probability of an outage for all assets or grid locations for each subset of outages and the probability an ignition is associated with an outage, given its characteristics, where:

$$P(\text{ignition}) = P(\text{ignition}|\text{outage}) \times P(\text{outage})$$

Model Target Event Dataset

The WDRM v3 draws on approximately 114,000 events in the target event dataset. The three datasets are described below.

1. Outages and Forced Outages

   - Source: PG&E's Integrated Logging Information System; and

   - Outages are defined as times when electricity ceases to be delivered to customers. Detecting outages is done electronically and is automatically recorded.

2. Hazards and Damages

   - Source: Post-PSPS Inspection Data; and

   - These are issues classified as potential hazards or equipment damage identified during the inspection of de-energized equipment before power can be restored after a PSPS event.

3. Ignitions

   - Source: PG&E's Historical Ignitions Data, 2015-2021 (approximately 2,500 CPUC-reportable ignitions and approximately 1,900 non-reportable ignitions); and

   - CPUC-reportable ignitions data is limited to fire events that meet the following criteria:

     - A self-propagating fire of material other than electrical and/or communication facilities;

     - The resulting fire traveled greater than one linear meter from the ignition point; and

     - The utility has knowledge that the fire occurred.

A fire caused damage to utility facilities and whose ignition is not associated with utility facilities are excluded from this reporting requirement.[69]

The ignition data set includes both CPUC-reportable and non-reportable ignitions, occurring with or without an outage. Fires that caused damage to utility facilities and whose ignition is not associated with utility facilities are excluded.

Collectively, the three types of events are described as failures. Failures are defined as incidents where damage to the grid has occurred, or damage to the environment has occurred due to grid equipment operation, even if no outage occurs.

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[69] D.14-02-015, Appendix C, p. C-3.

The failures data includes events that occurred:

- Within the boundaries of PG&E's overhead distribution lines only;
- From 2015 through 2021; and
- During fire season (June through November).

The target failure dataset excludes:

- Outages directly caused by wildfires;
- Outages or ignitions caused by underground equipment; and
- Outages that occur outside of the fire season (December through May).[70]

Attributes of the target set events that are used to define 17 non-overlapping subsets in the WDRM v3 are summarized in the following table.

[70] Events that occur outside of the fire season are excluded to avoid training the model on events due to causes that are not viable during the fire season, such as iced lines, snow loading, water damage, and water facilitated outages. Including such events would run the risk of training the WDRM to estimate wildfire risk in cases where there is none.

TABLE PG&E-6.2.1-1:
WDRM v3 SUBSET CHARACTERISTICS

Line No.	Subset	Voltage Category	Equipment Type	Cause	Sub-cause	Modeling Category	Model Type[(a)]
1	Vegetation_other	Any	Any	Vegetation	Other	Object Contact	MaxEnt
2	Primary_conductor	Primary	Conductor	Any	NA	Equipment	MaxEnt
3	Vegetation_branch	Any	Any	Vegetation	Branch	Object Contact	MaxEnt
4	Vegetation_trunk	Any	Any	Vegetation	Trunk	Object Contact	MaxEnt
5	Animal:_bird	Any	Any	Animal	Bird	Object Contact	MaxEnt
6	Secondary_ Conductor	Secondary	Conductor	Any	NA	Equipment	MaxEnt
7	Other_equipment_ Type	Any	Other	Any	NA	Equipment	MaxEnt
8	Third_party_balloon	Any	Any	Third party	Balloon	Object Contact	MaxEnt
9	Third_party_other	Any	Any	Third party	Other	Object Contact	MaxEnt
10	Third_party_vehicle	Any	Any	Third party	Vehicle	Object Contact	MaxEnt
11	Animal_squirrel	Any	Any	Animal	Squirrel	Object Contact	MaxEnt
12	Voltage_control equipment_type	Any	Voltage Control	Any	NA	Equipment	MaxEnt
13	Animal_other	Any	Any	Animal	Other	Object Contact	MaxEnt
14	Support_structure equipment_cause	Any	Support Structure	Equipment	Structural	Support Structure/ Transformer	Asset Attribute
15	Support_structure equipment_electrical	Any	Support Structure	Equipment	Electrical	Support Structure/ Transformer	Asset Attribute
16	Transformer equipment_leaking	Any	Transformer	Equipment	Leaking	Support Structure/ Transformer	Asset Attribute
17	Transformer equipment_cause	Any	Transformer	Equipment	Failure	Support Structure/ Transformer	Asset Attribute

(a) For subsets with outages driven by environmental determinants, such as vegetation caused outages, the WDRM v3 employs a MaxEnt model structure, with primarily spatially varying covariates resulting in grid pixel level estimates of P(outage).

For modeling categories that relate to equipment failures due to internal attributes, such as transformers and support structures, the WDRM v3 employs Asset Attribute models fit via Random Forest to one row of data per asset year.

A third model type, Logistic Regression, is used to estimate the probability of ignitions associated with outages, given outage characteristics.

The event counts, ignition counts, and ignitions per-outage rates for all 17 subsets are shown in the table below, sorted from highest to lowest event count. The difference in ignition counts and ignitions per outage, demonstrate the variation among causal pathways leading to failures and the likelihood to cause an ignition.

TABLE PG&E-6.2.1-2:
WDRM v3 TARGET DATASET

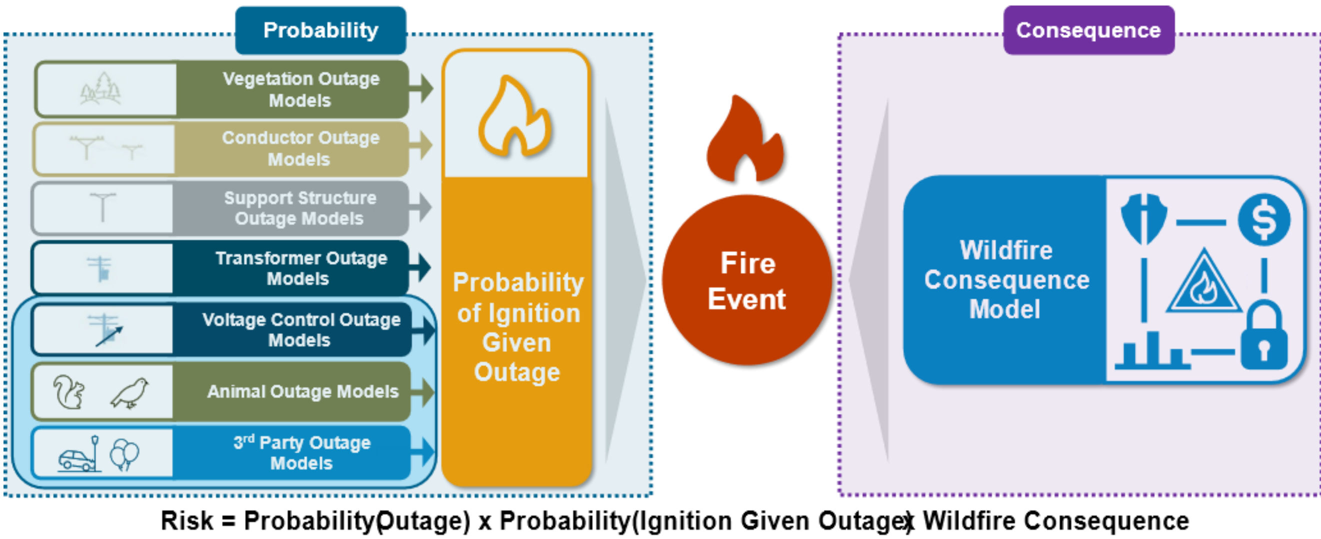
Line No.	Subset	Event Count	Ignition Count	Ignition per Outage
1	Other_equipment_type	46,981	316	0.67%
2	Primary_conductor	12,343	974	7.89%
3	Transformer_equipment_cause	8,809	62	0.70%
4	Third_party_vehicle	6,952	265	3.81%
5	Vegetation_branch	6,912	406	5.87%
6	Animal_bird	4,831	219	4.53%
7	Support_structure_equipment_cause	4,631	194	4.19%
8	Vegetation_trunk	4,388	329	7.50%
9	Secondary_conductor	3,801	216	5.68%
10	Animal_squirrel	3,694	40	1.08%
11	Third_party_other	2,202	102	4.63%
12	Third_party_balloon	2,127	103	4.84%
13	Support_structure_equipment_electrical	2,096	582	27.77%
14	Vegetation_other	1,655	184	11.12%
15	Transformer_equipment_leaking	1,126	0	0.00%
16	Animal_other	834	106	12.71%
17	Voltage_control_equipment_type	502	99	19.72%
18	Totals	113,884	4,197	3.69%

<u>Wildfire Consequence (CoRE)</u>

WFC refers to the impact from an event in terms of damage and/or hazard posed to the natural and built environment. It includes all causal steps from the initial ignition to the potential extent of wildfire spread. This includes both the Burn Probability and the Wildfire Consequence identified in the WMP Guidelines. Inherent to PG&E's risk framework, the Burn Probability is not a probabilistic assessment, but a deterministic assessment and for this reason is included in the Wildfire Consequence step and not in the Wildfire Likelihood.

The CoRE varies across the region based on simulated fire outcomes using detailed fuels, weather, and topography data. There is one CoRE value for each 100 x 100-meter (m) location along the grid (a grid pixel) and the CoRE values are highest under location-specific conditions that simulate destructive fire[71] outcomes. CoRE is generally higher at locations that are typically dry and windy with abundant burnable fuel. Figure PG&E 6.2.1-2 below shows the both the probability and consequence sides of the risk framework.

FIGURE PG&E-6.2.1-2:
PROBABILITY AND CONSEQUENCE



The WFC Model uses four sources of data to determine Fire Hazard Intensity or fire severity:

- Outputs from 2021 updated simulations from Technosylva;
- Satellite detected fires from VIIRS (infrared satellite);
- CAL FIRE data on fire outcomes correlated to VIIRS fires (used to assign MAVF CoRE values); and
- Daily estimates of the 1-5 scaled R-score provided by the FPI produced for PSPS models for every 2 x 2-kilometer square in PG&E's service territory. See Section 8.3.6 for a more detailed description of the FPI model.

WFC or Fire Hazard Intensity is calculated for each location along the electric assets and for a given day in the June through November fire season. Each specific point in time and space is assessed for destructive potential.

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71 PG&E defines a Destructive Fire as a fire that destroys 100 or more structures but does not result in a serious injury or fatality.

PSPS Risk Framework

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 bowtie model that evaluates safety, reliability, and financial consequences. The PSPS consequence model also includes a customer classification weighting that includes medical baseline and life support customers. The purpose of establishing a customer weighting is to identify and prioritize customers and circuits that include vulnerable customer populations that are at higher risk.

The basis of the model is a 12-year customer lookback that is informed by two meteorology models (FPI, and 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 (discussed in Section 8.3.5.1).

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.

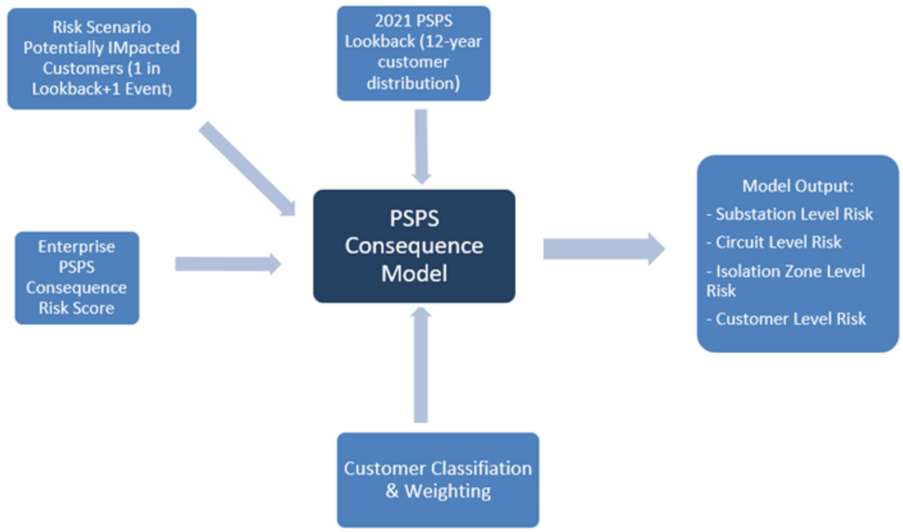
Risk drivers that the IPW model accounts for include the probability of wind-driven outage for each grid cell associated with the distribution system plus the probability of tree overstrike risk.

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

Starting in January 2023, PG&E incorporated additional customers into the PSPS consequence model who could be impacted and classified them as Potentially-Impacted Customers (PIC). This recognizes that not every customer in the historical backcast may be captured and provides a minimum threshold of PSPS risk for such customers. Adding the PICs roughly doubles the potentially affected customers and impacts circuit-based risk prioritization during PSPS events.

The inputs and outputs from the PSPS Consequence model are shown in Figure PG&E-6.2.1-3 below.

FIGURE PG&E-6.2.1-3:
PSPS CONSEQUENCE MODEL



6.2.2 Risk and Risk Components Calculation

The electrical corporation must calculate each risk and risk component defined in Section 6.2.1. Appendix B, "Calculation of Risk and Risk Components," provides additional requirements on these calculations. These are the minimum requirements and are intended to establish the baseline evaluation and reporting of all electrical corporations. If the electrical corporation identifies other key factors as important, it must report them in the WMP in a similar format.

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. Figure 6-2 provides an example of a calculation schematic is provided for the equipment likelihood of ignition.

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:

- *<u>Additional Input Parameters</u> beyond the minimum requirements for a specific risk component;*
- *<u>Calculations of Additional Outputs</u> beyond the minimum requirements for a specific risk component; and*
- *<u>Calculations of Additional Risk Components</u> defined by the electrical corporation in Section 6.2.1.*

The process used to combine risk components must be summarized for each relevant risk component. This process must align with applicable CPUC decisions regarding the inclusion of Risk Assessment and Mitigation Phase (RAMP) filings. If scaling factors (such as multi- attribute value functions [MAVFs] or representative cost) are used in this combination, the electrical corporation must present a table with all relevant information needed to understand this procedure. The electrical corporation must organize this discussion into the following two subsections focusing on likelihood and consequence.

6.2.2.1 Likelihood

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

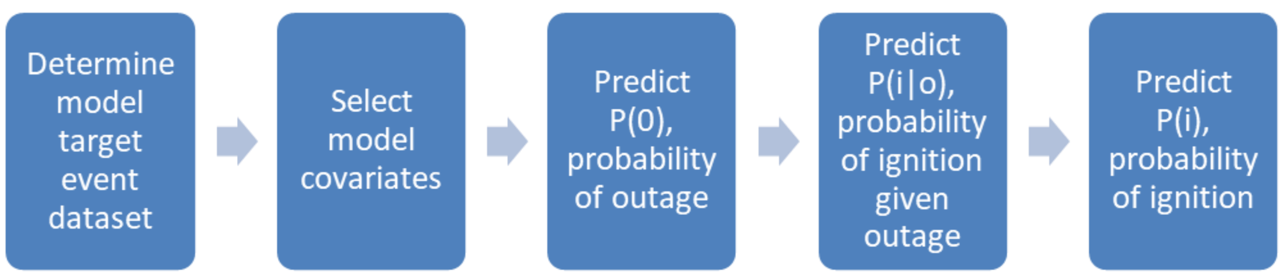
- *Ignition likelihood:*
  - *Equipment failure likelihood of ignition;*
  - *Contact from vegetation likelihood of ignition;*
  - *Contact from object likelihood of ignition;*
- *Burn probability; and*
- *PSPS likelihood.*

In this section we describe how we calculate event likelihood (LoRE) and the data that is used to make those calculations. As requested by Energy Safety, the LoRE calculations address the ignition likelihood from equipment failure, contact from vegetation, and contact from object. This section also addresses Burn Probability and PSPS likelihood.

Ignition Likelihood: Equipment Failure, Contact from Vegetation, Contact from Object

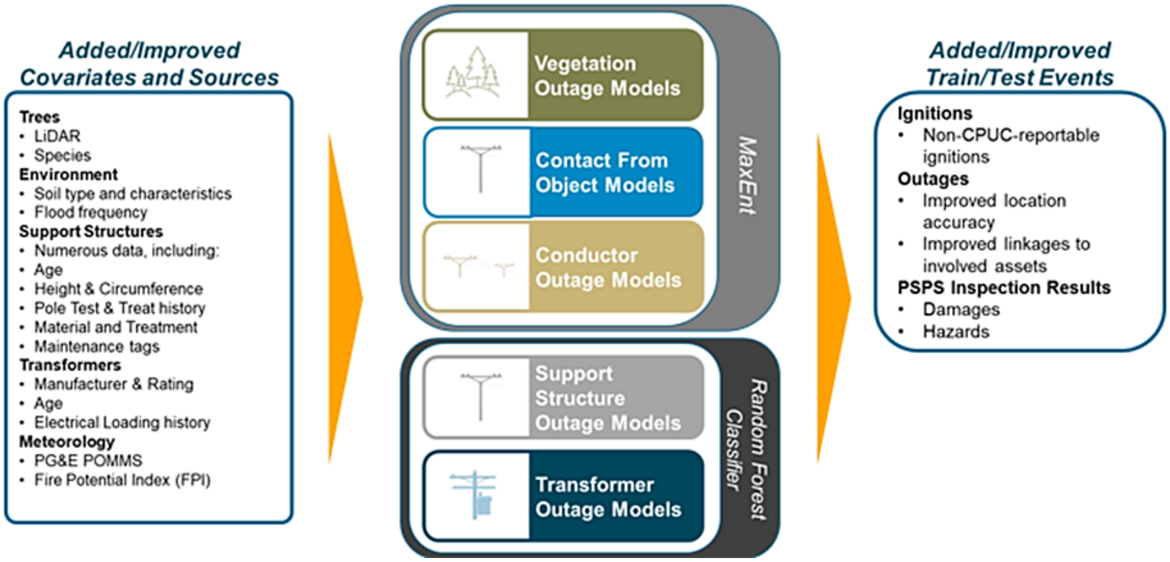
Figure 6-2-1 below shows the steps for calculating LoRE.

**FIGURE 6-2-1:
CALCULATING LoRE**



As displayed in Figure PG&E-6.2.2-1 below, the WDRM Risk Analysis Framework, LoRE is calculated using machine learning algorithms such as Maximum Entropy and Random Forest.

FIGURE PG&E-6.2.2-1:
WILDFIRE DISTRIBUTION RISK MODEL V3 INPUTS, ALGORITHMS, AND TRAINING DATA SETS



The WTRM considers 47 components, which were placed in a component grouping based on the following considerations:

- Similar asset lifecycle;
- Sensitivity to similar threats and hazards; and
- Similar Asset Management strategy.

The resulting nine component groups are:

- Group A Conductor: The conductor grouping includes conductor, jumpers, shield wires, Optical Ground Wire, armor rod, aviation marker balls, and smart grid devices. All the components in the group are subject to the same threats and hazards, or a subset of the threats and hazards.
- Group B Insulator: The insulator grouping includes insulators, flying bells and grading rings. All the components in the group are subject to the same threats and hazards, or a subset of the threats and hazards component.
- Group C Non-Steel Structures (i.e., Wood Poles): The non-steel structure grouping includes treated wood poles, wood crossarms and bird and animal guards. All the components in the group are subject to the same threats and hazards, or a subset of the threats and hazards.
- Group D Steel Structures (Including Steel Poles and Lattice Steel Structures): The steel structure grouping includes steel structures as the primary component. The other components in the group are leg members, non-leg members, crossarm members and bird and animal guards. There are also small populations of composite (fiberglass) poles, concrete poles, and hybrid poles. Hybrid poles are

those poles that have a concrete pole base and tubular steel pole top. While all the components in the group are subject to the same threats and hazards, composite poles may also be subject to ultraviolet degradation. They also have the same or similar life cycle.

- Group E Foundations: The foundation grouping includes foundations, stub angles and anchor bolts. All the components in the group are subject to the same threats and hazards, or a subset of the threats and hazards, as the primary component.

- Group F Switches: The switch grouping includes switches as the primary component. Other components in the group are distribution equipment, switch insulator, potential transformer, contact-live part, quick break attachment, interrupter, battery, and operating assembly.

- Group G Above-Grade Hardware: The component grouping for above-grade hardware consists of two sub-groupings.

  – Sub-Group 1 consists of components where the life cycle closely aligns with that of the structure. These include the hanger plate and bolts.

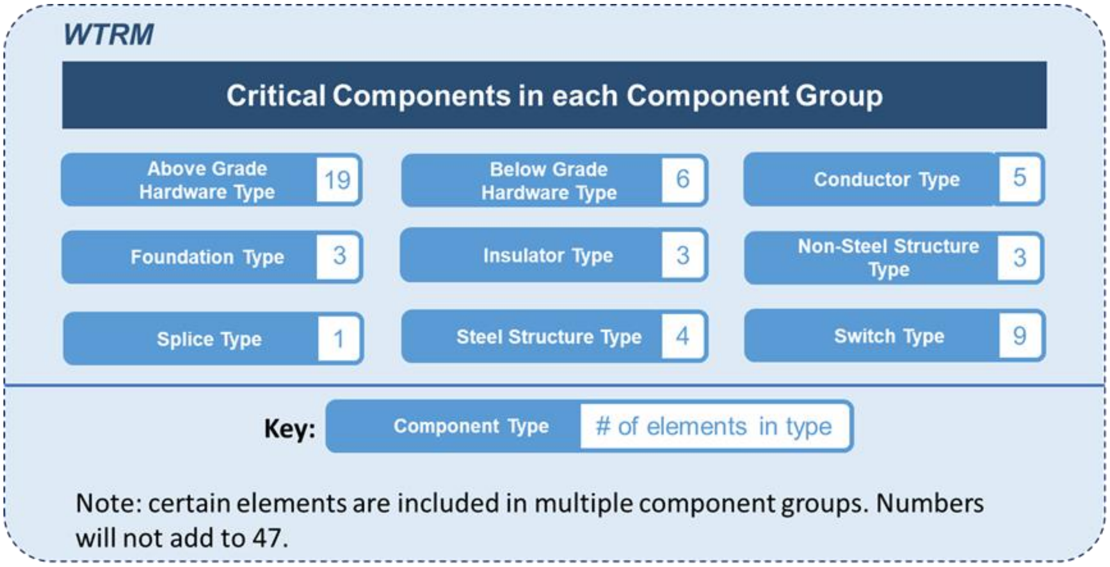
  – Sub-Group 2 consists of components whose life cycle more closely aligns with that of conductor.

- Group H Below-Grade Hardware: The below-grade hardware grouping includes the anchor system, ground wire, and guy system.

- Group I Splice Type: The splice type component group captures threats and hazards that are specific to conductor splices. The prevalence of conductor splices are treated as uncertainty metrics for the WTRM. While invariably linked to conductors, their performance from an annual probability of failure perspective is computed separately and then combined with the conductor component group for the composite risk value.

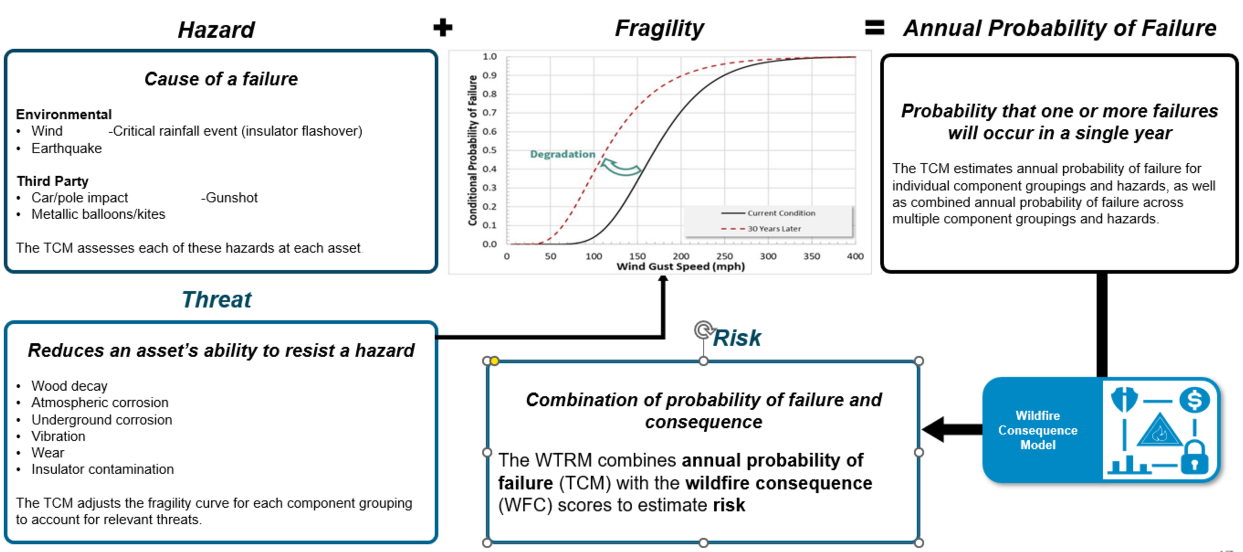
The 47 components included in the WTRM, separated into the nine critical component groups described above, are reflected in Figure PG&E-6.2.2-2 below.

FIGURE PG&E-6.2.2-2:
WTRM COMPONENT GROUPS



A probability of outage is calculated for each of these components through the use of a fragility curve as shown in Figure PG&E-6.2.2-3 below. This fragility curve is adjusted according to a range of threats. The probability of outage is combined with Wildfire Consequence to produce Wildfire Risk.

FIGURE PG&E-6.2.2-3:
OVERALL FRAMEWORK OF PG&E'S WILDFIRE TRANSMISSION RISK MODEL



Burn Probability

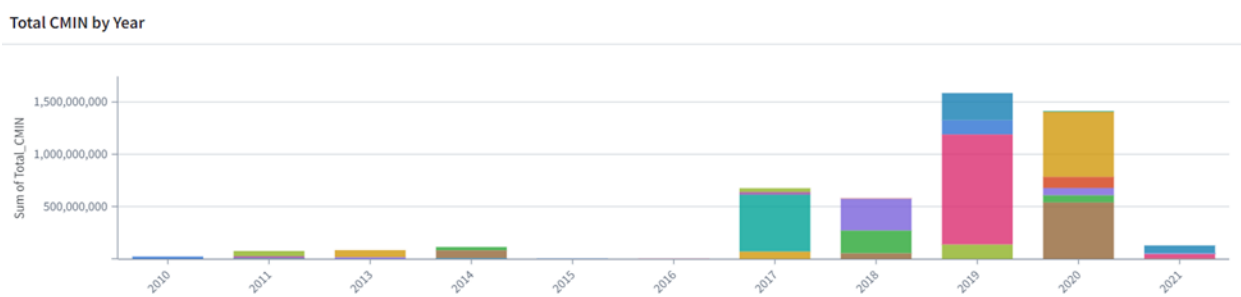
Burn Probability is discussed in Section 6.2.1 above.

PSPS Likelihood

The basis of PSPS likelihood is estimated based on two data inputs: (1) PSPS lookback, and (2) potentially impacted customers. This data flow can be seen in Figure PG&E-6.2.2-3 above.

The basis of PSPS likelihood is estimated by applying the current PSPS protocols against historical climatological dataset informed by two meteorology models (FPI and IPW). This backcast was performed through 2010 to provide an annual estimation of PSPS likelihood of PG&E's system. Of note, seen in Figure PG&E-6.2.2-4 below, since 2017 the annual likelihood of PSPS is higher than the earlier years, but 2021 and 2022 has seen a drop-off in PSPS events.

FIGURE PG&E-6.2.2-4:
PSPS BACKCAST EVENTS STARTING 2010



Second, we wanted to capture potentially impacted customers. It is still possible that a customer in HFTD and High Fire Risk Area (HFRA) could be impacted by PSPS, despite not being in the historical backcast. Instead of showing these customers as 0 PSPS risk, PG&E includes a risk scenario of PIC based on system configuration and includes the likelihood of PSPS as 1 in lookback period + 1 year (13 year) event. Even though the likelihood of a PSPS event for these PIC is small, this allows separation for customers potentially impacted by PSPS and the customers not expected to experience PSPS.

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

6.2.2.2 Consequence

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

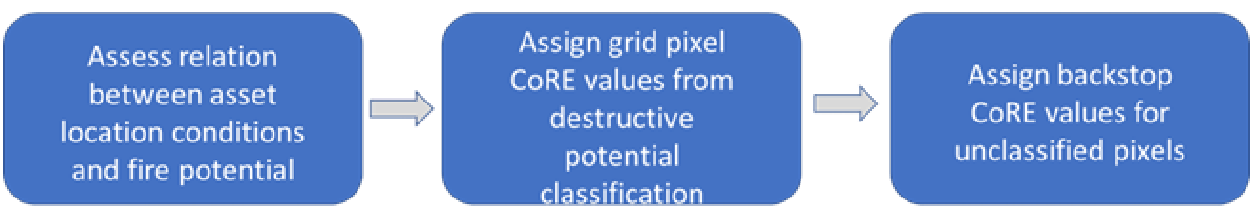
- *Wildfire consequence;*
- *Wildfire hazard intensity;*
- *Wildfire exposure potential;*
- *Wildfire vulnerability;*
- *PSPS consequence;*
- *PSPS exposure potential; and*
- *PSPS vulnerability.*

In Section 6.2.1 we describe how PG&E calculates CoRE and the data that is used in the calculations. The CoRE calculations described here in Section 6.2.2.2 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 6-2-2 below shows the steps for calculating CoRE.

FIGURE 6-2-2:
CALCULATING CoRE

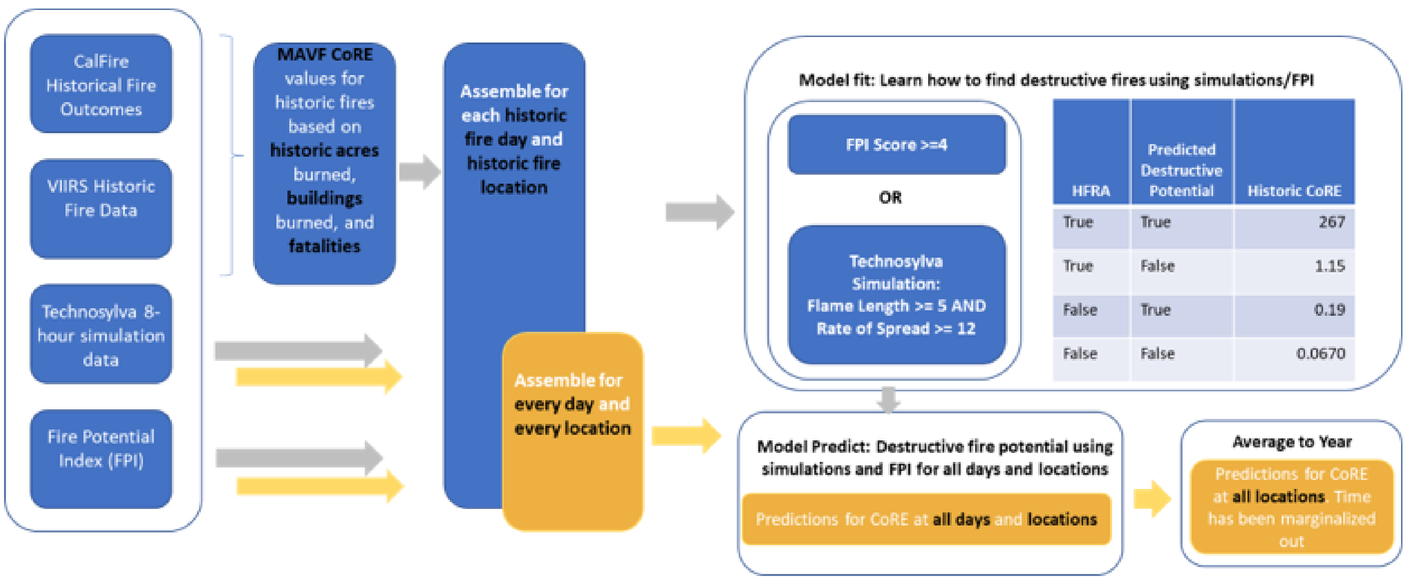


CoRE Processing Steps

Figure PG&E-6.2.2-5 below shows the CoRE processing steps. As seen on the left side of Figure PG&E-6.2.2-5, if a day/location point evaluates to destructive potential with either the Technosylva simulation or the FPI R-score, it is considered to have consequences consistent with the average of MAVF CoRE value assigned to destructive fires from the VIIRS data set. The use of FPI R-score in addition to the

Technosylva simulations allows for the marginalization of consequence values across the entire fire season, not just the worst weather days approach used by Technosylva.

FIGURE PG&E-6.2.2-5:
CoRE PROCESS STEPS

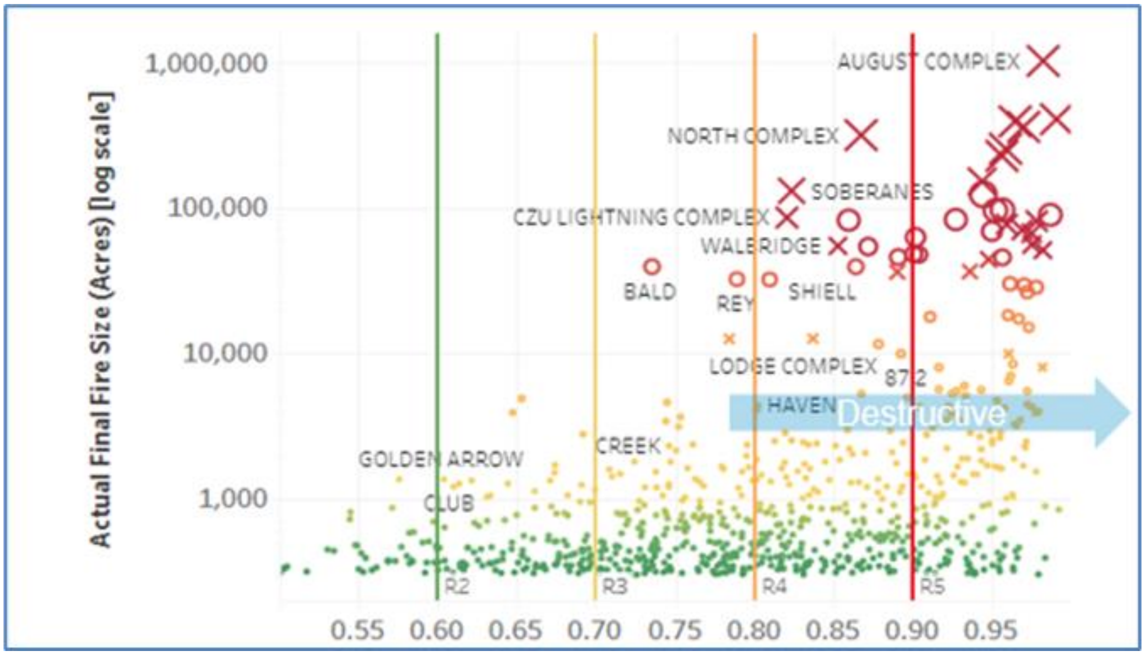


<u>Wildfire Hazard Intensity: The Relationship Between Asset Location Conditions and Fire Potential</u>

Historic fires from the VIIRS data are combined with CAL FIRE and other agency data on outcomes (buildings burned, acres burned, fatalities) to produce MAVF CoRE consequences for historic fires. The available data is joined to Technosylva WRRM 8hr simulations and to FPI R-score for all times and locations.

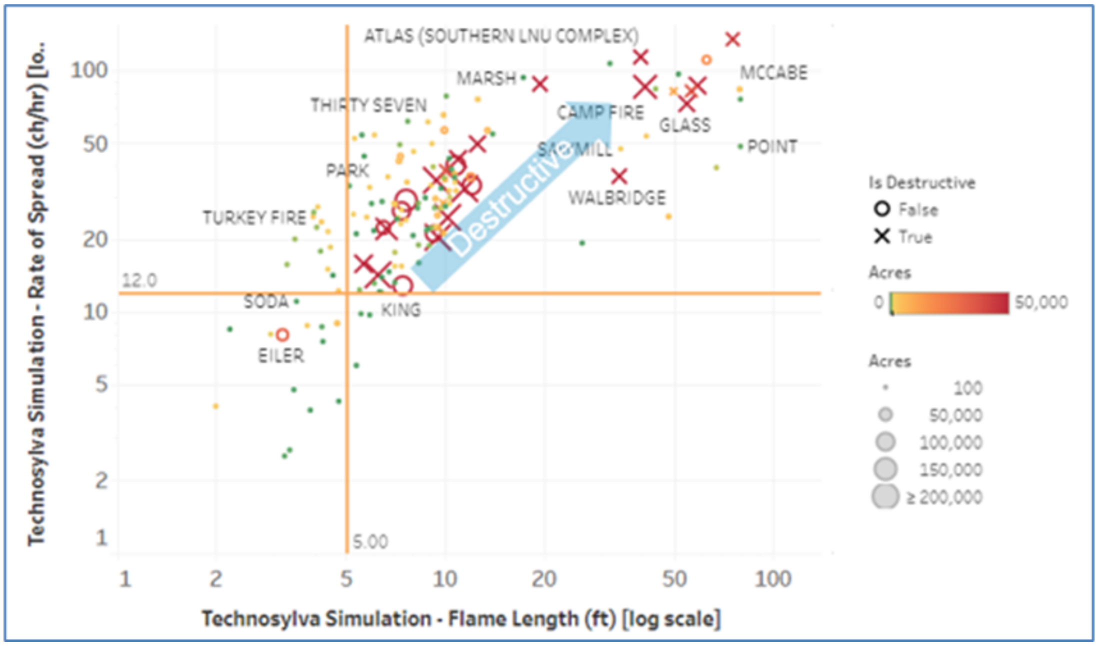
The relationship between the Technosylva simulations and the historic data on destructive fires is illustrated in Figure PG&E-6.2.2-6 below. Destructive fires are denoted by the red X's. An FPI R value of 4 or greater is used to identify destructive fire locations.

FIGURE PG&E-6.2.2-6:
TECHNOSYLVA SIMULATION AND DESTRUCTIVE FIRE RELATIONSHIP



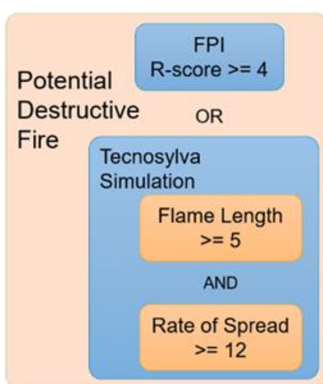
The relationship between the FPI R-score and the historic fire data was examined as well. Destructive fires are denoted by the red X's and plotted with the rate of spread and Flame Length Technosylva simulation results for each wildfire in Figure PG&E-6.2.2-7 below. Thresholds can be drawn for both factors where destructive fires are characterized by a Rate of Spread greater than 12 chains/hour and a Flame Length greater than 5 feet.

FIGURE PG&E-6.2.2-7:
FPI R SCORE AND DESTRUCTIVE FIRE RELATIONSHIP



As shown in Figure PG&E-6.2.2-8 below, these identified thresholds establish the classifier conditions that indicate (predict) that there may be a potentially destructive fire. Conversely, non-destructive potential is predicted when the classifier conditions are not met. Each of the predicted destructive/non-destructive outcomes has an associated mean MAVF CoRE consequence from the observed, historic outcomes. Predicted destructive potential/non-destructive potential are computed both inside and outside the HFRA to complete this partition of the day/location data.

FIGURE PG&E-6.2.2-8:
DESTRUCTIVE POTENTIAL CLASSIFIER



Using the classifier described above and the starting locations of historical fires, the mean MAVF was determined for a matrix of HFRA designation and the destructive potential prediction for each historical fire location as shown in Table PG&E-6.2.2-1 below.

TABLE PG&E-6.2.2-1:
WILDFIRE CONSEQUENCE FPI MODEL

HFRA	Predicted Destructive Potential	CoRE from Mean MAVF of Historic Fires
True	True	267
True	False	1.15
False	True	0.195
False	False	0.0670

Assigning Grid Pixel CoRE Values From the "Destructive Potential" Classification

To project CoRE values, the covariates are computed for as many pixels as possible. FPI R-scores are computed for all times and most pixels. Technosylva fire simulations are computed for worst condition days and at roughly 200m intervals along grid asset locations.

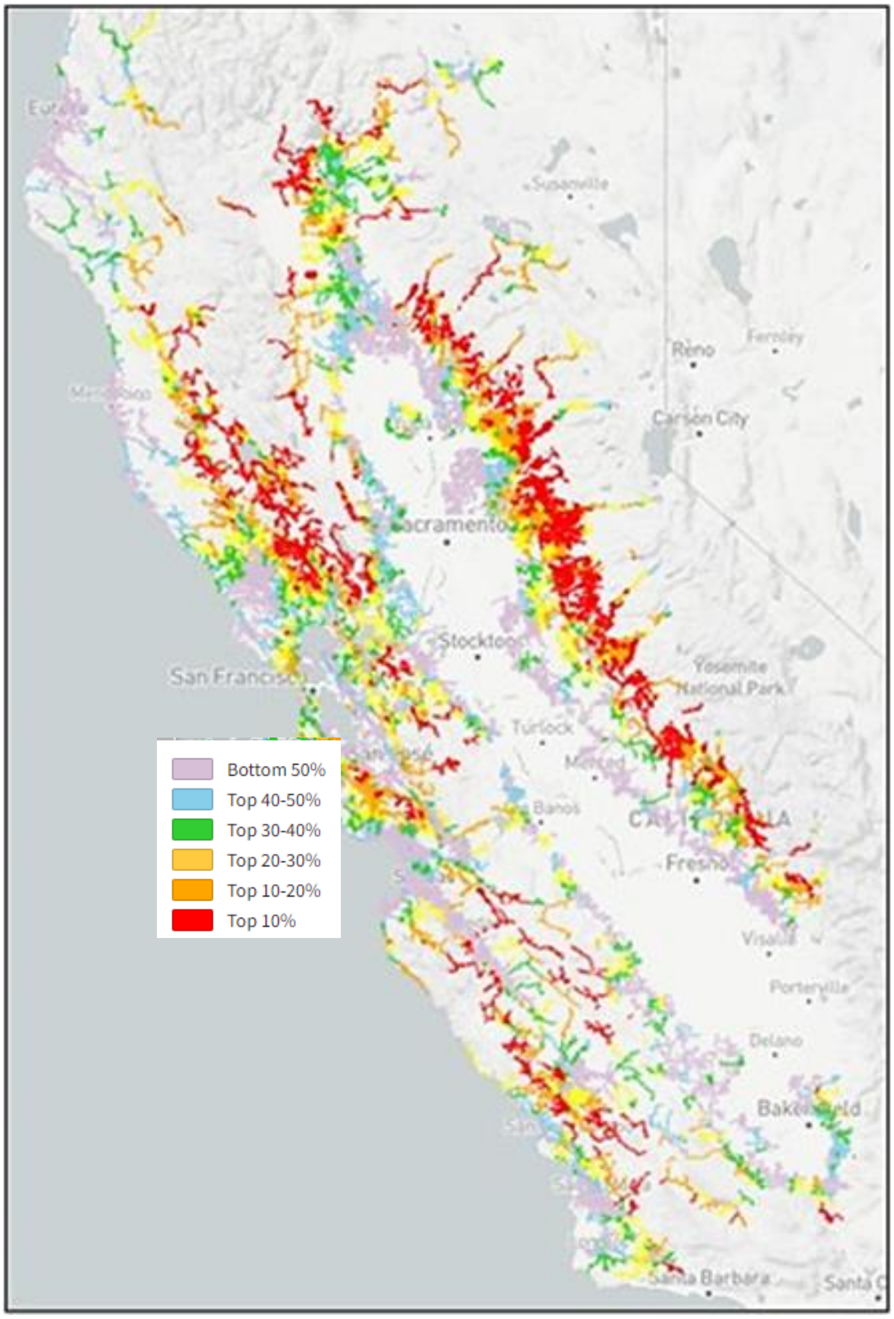
Technosylva does not produce simulations in locations where it is unlikely that a wildfire could be sustained such as urban, industrial, and agricultural areas.

Wildfire Exposure Potential: WDRM v3 Consequence Pixel Map

For each day in the fire season, the FPI R-score and Technosylva simulation results are classified for each pixel as shown in Figure PG&E-6.2.2-9 below. From the pixel destructive potential classification, the appropriate CoRE value is assigned from the WFC. The final CoRE value for each pixel is the aggregate of the daily CoRE values.

Figure PG&E-6.2.2-9 is a color-coded map of average consequence value during the fire season. The high consequence values are typically found in the foothill regions of the distribution grid.

FIGURE PG&E-6.2.2-9:
WILDFIRE CONSEQUENCE PIXEL MAP



Wildfire Vulnerability

Wildfire vulnerability is represented as an input to the Wildfire Consequence model in the form of demographic data layers. In future versions of the Wildfire Distribution and

Wildfire Transmission risk models, egress capability will be assessed for potential fires originating from locations along electric grid assets. As discussed in Section 6.7, data characterizing vulnerable populations are proving to have predictive value in identifying locations with higher egress requirements.

PSPS Consequence, Exposure Potential, and Vulnerability

PSPS consequence is based on the backcast of PSPS impact based on 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. Additionally, before and after the weather event, there is additional duration added to account for switching and patrol prior to restoration. 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 their critical customer categorization shown in Table PG&E-6.2.2-2 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-6.2.2-2:
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

6.2.2.3 Risk

The electrical corporation must discuss how it calculates each risk and the resulting overall utility risk defined in Section 6.2.1. The discussion in this section must include at least the following:

- *Ignition risk;*
- *PSPS risk; and*
- *Overall utility risk.*

PG&E calculates Overall Utility Risk as the sum of Ignition or Wildfire Risk + PSPS risk as shown in above Figure 6-1.

To calculate overall utility risk, we aggregate the risk scores from the Enterprise Risk Model. PG&E's Overall Utility Risk is calculated as:

$$\boldsymbol{Overall\ Utility\ Risk} = Ignition/Wildfire\ Risk\ (Dx,\ Tx,\ Sub) + PSPS\ Risk\ (Backcast,\ WCS)$$

$$\boldsymbol{Enterprise\ Risk}(\boldsymbol{MAVF}) = (23{,}082\ Dx + 771\ Tx + 14\ Sub) + \ (2{,}170 + 49) = 26{,}086$$

Ignition/Wildfire Risk Scores

For each grid pixel along the overhead distribution system, the WDRM assigns an ignition or wildfire risk score based upon the product of probability of ignition (P(i), or LoRE) and consequence (CoRE). The principal output of the WDRM is an assigned wildfire risk score for each grid pixel for each model subset. The subset-level grid pixel risk values can be summed across subsets to compute composite risk values. Grid pixel risk values can also be aggregated with their associated circuit segments to derive circuit segment risk values. These computations are described in the following sections.[72]

What we describe below is a detail of compositing for WDRM, but the same risk components concepts apply for Transmission and Substation.

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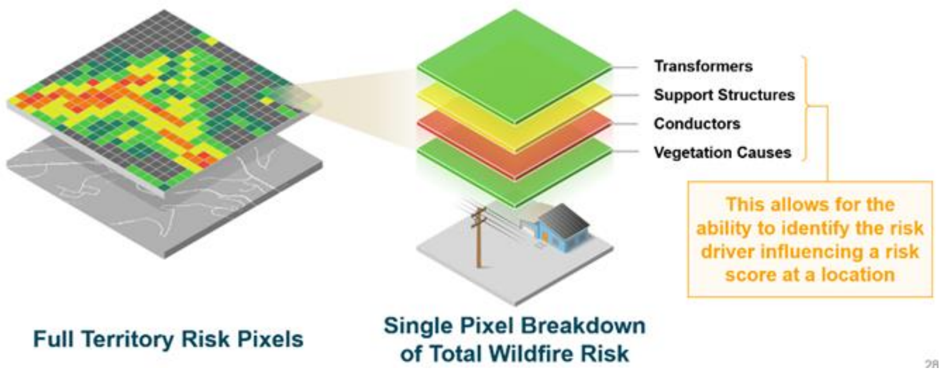
72 For any pixel that is null either its ignition or consequence value, the wildfire risk value will be missing. Missing risk values are rare but can happen due to small gaps in covariate or fire simulation spatial coverage.

Compositing Ignition/Wildfire Risk Scores

Outputs from the WDRM are a key input into work planning and prioritization for risk mitigation programs. The WDRM model subsets can be combined in different ways to provide risk values and priority rankings for different mitigation initiatives. The ability to build custom composites of risk at the driver, assets, pixel, or other level, is a key improvement of WDRM v3 over prior versions Figure PG&E-6.2.2-10 below demonstrates how the risk model composites various subsets.

FIGURE PG&E-6.2.2-10:
COMPOSITING MODEL SUBSET RISK



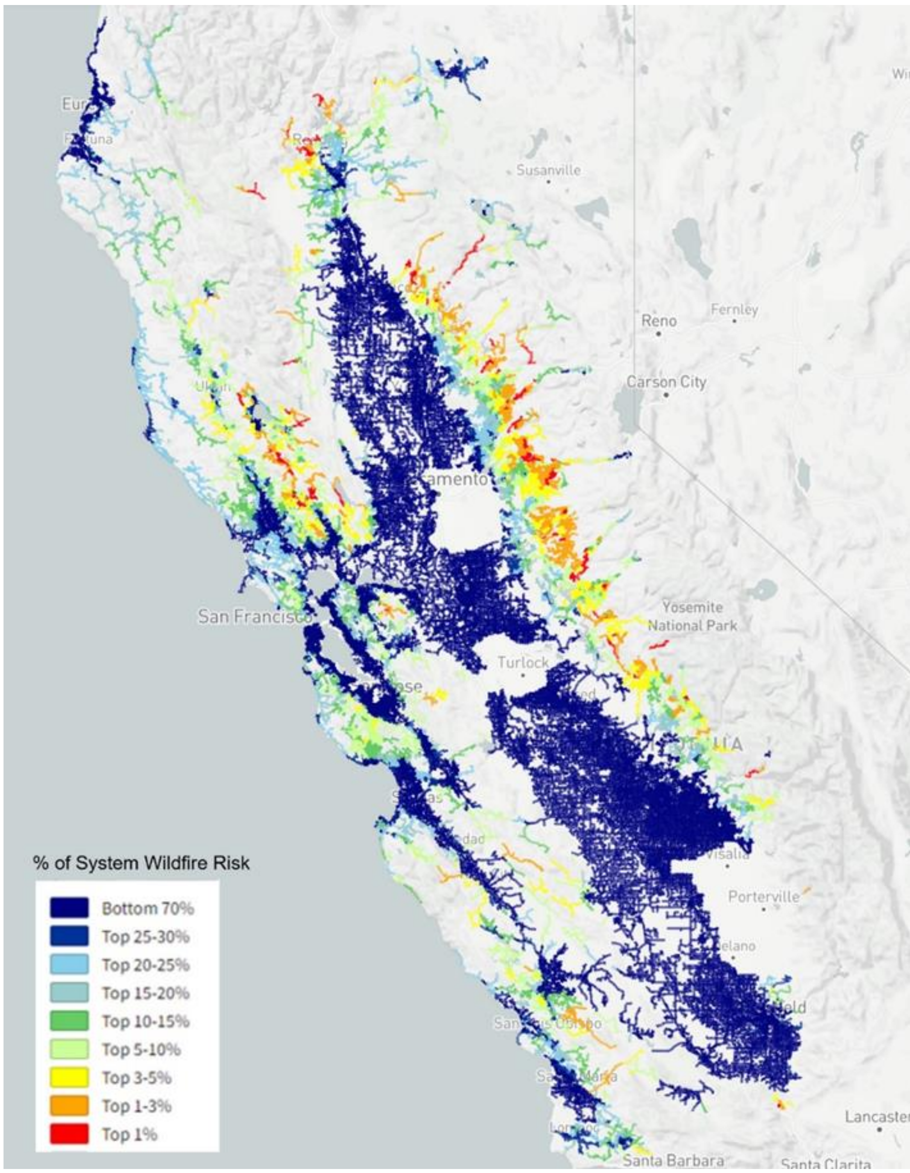
WDRM v3 composites can be built to support specific mitigation strategies. We use the WDRM to support our system hardening, support structures, and transformer mitigations. Table PG&E-6.2.2-3 below shows how compositing has been done for Vegetation Management and System Hardening.

**TABLE PG&E-6.2.2-3:
VM AND SYSTEM HARDENING COMPOSITING**

Subset	VM	System Hardening
Vegetation Subsets		
Vegetation (Trunk) Caused	X	X
Vegetation (Branch) Caused	X	X
Vegetation (Other) Caused	X	X
Animal Subsets		
Animal Bird		X
Animal Squirrel		X
Animal Other		X
Third-Party Subsets		
Third-Party Vehicle		X
Third-Party Balloon		X
Third-Party Other		X
Conductor and Other Equipment Subsets		
Primary Conductor		X
Secondary Conductor		X
Other Equipment Type		X
Voltage Control Equipment		X
Support Structure Subsets		
Support structure – Equipment Caused		X
Transformer Subset		
Transformer – Equipment Caused		X

Figure PG&E-6.2.2-11 below is a map of the ignition/wildfire risk values for the System Hardening composite model.

FIGURE PG&E-6.2.2-11:
SYSTEM HARDENING COMPOSITE RISK



PSPS Risk Score

Based on the PSPS Likelihood and PSPS Consequence as described above, we calculate the probability and consequence of each individual customer service_point_ID to arrive at a PSPS risk score per customer. Next, we take the customer risk score and apply a critical customer weighting based on their customer classification. Lastly, we aggregate all the customers' risk score together to determine the overall PSPS Risk Score. The results of the PSPS Consequence Model are then calibrated to PG&E's Enterprise Risk Model's MAVF Risk Score for PSPS.

6.2.3 Key Assumptions and Limitations

Since the individual elements of risk assessment are interdependent, the interfaces between the various risk models and mitigation initiatives 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. This must include the following:

- *<u>Key modeling assumptions</u> made specific to each model to represent the physical world and to simplify calculations;*
- *<u>Data standards</u>, which must be consistently defined (e.g., weather model predictions at a 30-feet [10-m] height must be converted to the correct height for fire behavior predictions, such as mid-flame wind speeds);*
- *<u>Consistency of assumptions and limitations</u> in each interconnected model, which must be traced from start to finish, with any discrepancies between models discussed; and*
- *<u>Stability of assumptions in the program</u>, including historical and projected changes.*

More mature programs regularly monitor and evaluate the scope and validity of modeling assumptions. Monitoring and evaluation categories may include:

- *<u>Adaptation of weather history</u> to current and forecasted climate conditions;*
- *<u>Availability of suppression resources</u> including type, number of resources, and ease of access to incident location*
- *<u>Height of wind driving fire spread</u>/wind adjustment factor calculation;*
- *<u>General equipment failure rates</u>/wind speed functional dependence for unknown components;*
- *<u>General vegetation contact rates</u>/wind speed functional dependence for unknown species;*
- *Height of electrical equipment in the service territory;*
- *<u>Stability of the atmosphere</u> and resulting calculation of near-surface winds;*
- *<u>Vegetative fuels</u> and fuel models including adaptations based on fuel management activities by other Public Safety Partners;*
- *<u>Combination of risk components/weighting of attributes</u> in alignment with most recent decision issued by the CPUC for inclusion in RAMP filings;*
- *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 6-2. The electrical corporation must summarize detailed assumptions made within models in accordance with the model documentation requirements in Appendix B.

TABLE 6-2:
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/Wildfire Consequence Equipment Likelihood of Ignition Contact from Object Likelihood of Ignition
The 2022 WDRM v3 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
Machine learning 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 machine learning tools are the primary output of the 2022 WDRM v3.	N/A	Ignition/Wildfire Risk (WDRM) Ignition Likelihood Equipment Likelihood of Ignition Contact from Object Likelihood of Ignition
Where there is limited or no data regarding mitigation program effectiveness, the model relies on mitigation effectiveness values developed by SMEs.	SME judgement is assumed to be a reasonable substitute for empirical data until such time as data can be collected/developed.	N/A	Ignition/Wildfire Risk (WDRM)

TABLE 6-2:
RISK MODELING ASSUMPTIONS AND LIMITATIONS
(CONTINUED)

Assumption	Rationale/Justification	Limitation	Applicable Model
WTRM builds on assumptions used by the Transmission OA Model. PG&E identified 47 components through a Failure Modes and Effects Analysis (FMEA) 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)
The prioritization of threat and hazard models for development and deployment to production systems.	Prioritization is driven by SME judgment. PG&E SMEs ranked the how critical a failure would be based on a threat-hazard pairing to prioritize the order of work.	N/A	Ignition/Wildfire Risk (WTRM)
Age data is required for each component in order for the WTRM to compute an annual failure rate.	Where age data is unavailable, conservative age assumptions are used.	N/A	Ignition/Wildfire Risk (WTRM)
Inclusion of "Potentially Impacted Customers Analysis" does not change the overall PSPS MAVF Risk Score.	While a large set of customers are being included as having PSPS impact, when calibrating the PSPS Risk Score in terms of MAVF, the overall risk is represented by historical performance. As such, all customers see a smaller contribution to the overall risk score, in which the overall risk scores does not change.	Additional scenarios being considered have no impact to the overall PSPS MAVF risk score.	PSPS Risk PSPS Consequence PSPS Likelihood Vulnerability of Community to PSPS
"Potentially Impacted Customers" is created as a 1 in 13 year frequency. Outage Duration is based on average outage duration from "12 year PSPS lookback".	"Potentially Impacted Customers" inherently do not show up in the "12 year PSPS lookback". As such, the frequency of an event is 1 year exceeding PG&E's lookback period in order to capture the potential for additional customers to be impacted. This is to capture the non-zero PSPS risk tied to customers that do not show up on the lookback.	The accuracy of the potentially impacted customers are proxied off the 12-year lookback data.	PSPS Risk PSPS Consequence PSPS Likelihood Vulnerability of Community to PSPS

TABLE 6-2:
RISK MODELING ASSUMPTIONS AND LIMITATIONS
(CONTINUED)

Assumption	Rationale/Justification	Limitation	Applicable Model
Critical Customer Weightings are based on high level SME judgement.	The assigning 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 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 CPZ risk ranking and prioritization initiatives	PSPS Risk PSPS Consequence PSPS Likelihood Vulnerability of Community to PSPS
PSPS Safety consequence is based off 50 percent PG&E PSPS planned and 50 percent unplanned long-duration outages across the 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
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
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[(b)]

TABLE 6-2:
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[(b)]
Machine learning 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 machine learning is that it allows the skillful explanation of future fires, outages, and ignitions by using large amounts of data and sophisticated algorithms.	Machine learning models are limited by the amount of data available and the sophistication of the current state-of-the-art algorithms.	FPI/IPW[(b)]

(a) The Enterprise Risk Model is used to calibrate all the wildfire and PSPS risk models listed in Table 6-1 above for the purpose of calculating overall utility risk.

(b) The FPI/IPW models are operational models and, therefore, do not appear in Table 6-1above.

6.3 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 6.2. These must include at least the following:

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

The risk scenarios described in Sections 6.3.1 and 6.3.2 below are the minimum scenarios the electrical corporation must assess in its wildfire and PSPS 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*
- *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)*

6.3.1 Design Basis Scenarios

Fundamental to any risk assessment is the selection of one or more relevant design basis scenarios (design scenarios). These scenarios will inform long-term mitigation initiatives and planning. In this section, the electrical corporation must identify the design scenarios it has prioritized from a comprehensive set of possible scenarios. The scenarios identified must be based on the unique wildfire and PSPS risk characteristics of the electrical corporation's service territory and achieve the primary goal and stated plan objectives of its WMP. At a minimum, the following design scenarios representing statistically relevant weather and vegetative conditions must be considered throughout the service territory.

For wind loading on electrical equipment, the electrical corporation must use at least four statistically relevant design conditions. It must calculate wind loading based on locally relevant 3-second wind gusts over a 30-year wind speed history during fire season in its service territory. The conditions are the following:

- *Wind Load Condition 1 – Baseline: The baseline wind load condition the electrical corporation use 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 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.

For weather conditions used in calculating fire behavior, the electrical corporation must use probabilistic scenarios based on a 30-year 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. The electrical corporation must consider the following two conditions:

- *Weather Condition 1 – Anticipated Conditions: 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*

- *Weather Condition 2 – Long-Term Conditions: The statistical weather analysis is representative of fire seasons covering the full 30-year history.*

The electrical corporation must state how it defines "fire weather" and "fire season" for the scenarios.

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 United States Forest Service.[73] *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 data and/or models the electrical corporation uses to establish locally*

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73 M. A. Finney, et al., A Metho d for Ensemble Wildland Fire Simulation (2011), Environmental Modeling & Assessment 16: 153-167.

M. A. Finney, et al., A Simulation of Probabilistic Wildfire Risk Components for the Continental United States (2011), Stochastic Environmental Research and Risk Assessment 25: 973-1000.

relevant weather data for these designs must be documented in accordance with the weather analysis requirements described in Appendix B.

For vegetative conditions not including short-term moisture content, the electrical corporation must use design scenarios including the current and forecasted vegetative type and coverage. The conditions it must consider include the following:

- *Vegetation Condition 1 – Existing Fuel Load: The wildfire hazard must be evaluated with the existing fuel load within the service territory, including existing burn scars and fuel treatments that reduce the near-term fire hazard;*

- *Vegetation Condition 2 – Short-Term Forecasted Fuel Load: The wildfire hazard must be evaluated considering the changes in expected fuel load over the 3-year Base WMP cycle (2023-2025). At a minimum, this must include regrowth of previously burned and treated areas; and*

- *Vegetation Condition 3 – Long-Term Extreme Fuel Load: The wildfire hazard must be evaluated considering the long-term potential changes in fuels throughout the service territory. This must include, at a minimum, regrowth of previously burned and treated areas and changes in predominant fuel types.*

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 basis scenarios used in its risk analysis. If the electrical corporation includes additional design scenarios, it must describe these scenarios and their purpose in the analysis. In addition, the electrical corporation must provide a table summarizing the following information:

- *Identification of each design basis scenario (e.g., Scenario 1, Scenario 2);*

- *Components of each scenario (e.g., Weather Condition 1, Vegetation Condition 1); and*

- *Purpose of each scenario.*

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. The risk modeling framework employed by PG&E aims to account for all scenarios in a single predictive model that are represented by the historical data sets used in model development. In doing so, some conditions considered by the extreme scenarios outlined by Energy Safety may not be represented in the historical data at this time. As part of PG&E's goal to continuously improve our risk modeling, we will seek methods to appropriately account for extreme scenarios in the future.

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

- Fire Season: May to November of each calendar year. This generally aligns with CAL FIRE's definition and the historical trend of wildfire activities.

- Fire Weather: is best represented as the fire danger ratings produced by the Fire Potential Index (FPI). Please see Section 8.3.6 for a detailed description of the FPI model.

As shown in Table 6-3, below are high-level summaries of the data for each of the prescribed scenarios: Wind, Weather, and Vegetation.

Weather

For operational models (FPI, IPW, OA, PSPS), current weather conditions are used alongside a 30-year meteorology. 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 Technosylva WFC 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-6.2.2-3) 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 6-3:
SUMMARY OF DESIGN BASIS 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

6.3.2 Extreme-Event Scenarios

In this section, the electrical corporation must identify extreme 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 6.3.1, the potential for high consequences from extreme events may provide additional insight into the mitigation prioritization described in Section 7.

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 and their purpose in the analysis. 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);*
- *Purpose of the scenario; and*
- *Table 6-4 provides an example of the minimum acceptable level of information.*

PG&E does not directly account for extreme-event scenarios as articulated in the WMP Guidelines in risk modeling. To the extent that an extreme scenario wildfire risk is realized coincident with other risk events, PG&E's plan is outlined in the Company Emergency Response Plan (CERP).

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 PG&E CERP uses common emergency response protocols and follows a recognized incident command system. For purposes of the CERP, 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.

As mentioned in Section 6.3.1, PG&E seeks to incorporate the potential impacts of more extreme conditions in future models. An example of extreme scenarios under consideration is shown in Table 6-4. This example builds on work that PG&E shared during the September 14, 2022, Energy Safety Risk Model Working Group meeting wherein PG&E is partnering with a number of academic institutions to study the future climate-driven risk of wildfire. Figure PG&E-6.3.2-1 illustrates the extreme wildfire risk we are studying.

FIGURE PG&E-6.3.2-1:
CLIMATE-DRIVEN RISK OF EXTREME WILDFIRE IN CALIFORNIA

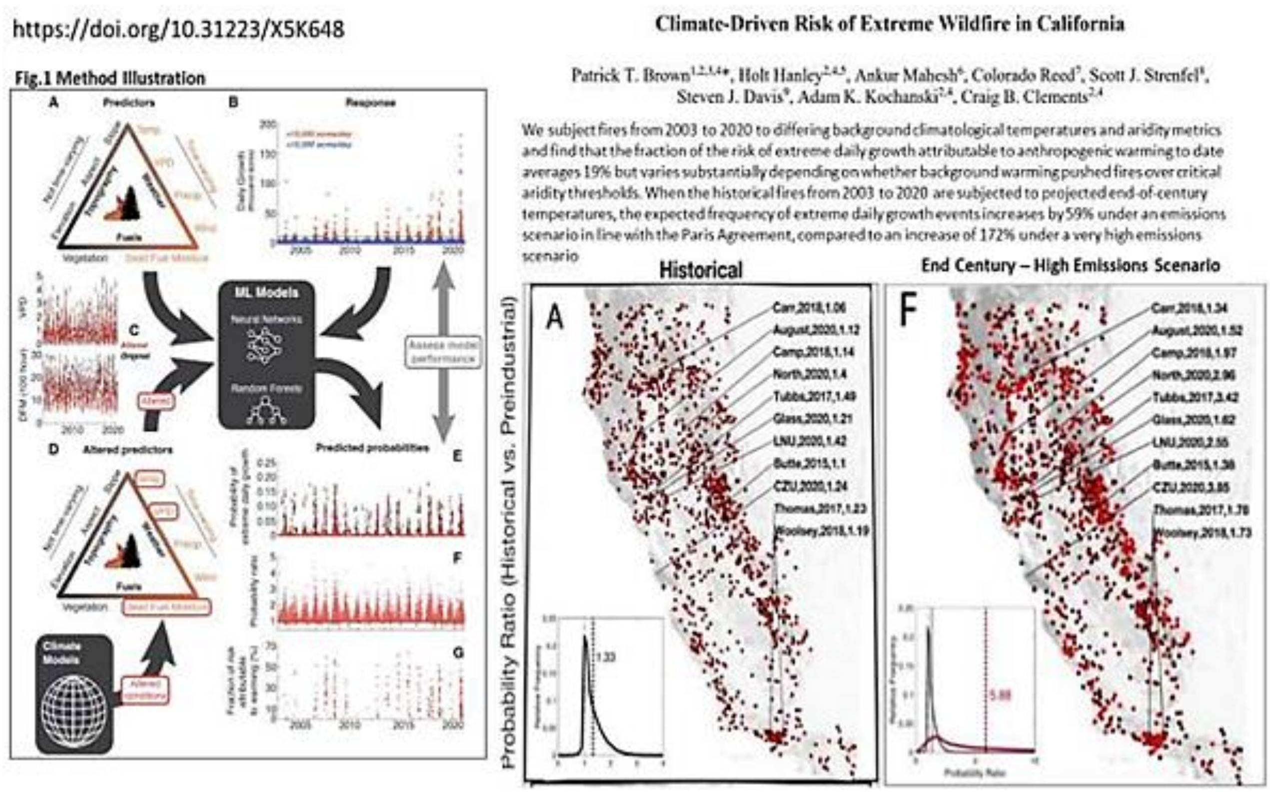

TABLE 6-4:
EXAMPLE OF EXTREME EVENT SCENARIOS UNDER CONSIDERATION

Scenario ID	Extreme-Event Scenario	Purpose
ES1	Vegetation Condition 3 Wind Load 2, 3, 4 Weather 2	Impact of climate change on vegetation fuels

6.4 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 6.2 for the scenarios discussed in Section 6.3.

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.

6.4.1 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.

6.4.1.1 Geospatial Maps of Top Risk Areas Within the HFRA

The electrical corporation must evaluate the outputs from its risk modeling to identify top risk within its HFRA (independent of where they fall with respect to the HFTD status). The electrical corporation must provide geospatial maps of these areas.

The maps must fulfill the following requirements:

- *Risk Levels: Levels must be selected to show at least three distinct levels, with the values based on the following:*
  - *Top 5 percent of overall utility risk values in the HFRA;*
  - *Top 5 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 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 system territory. We first measure the top 5 percent, top 5 to 20 percent, and bottom 80 percent by the percent risk across the entire system territory and then we filter these values to include only the circuitry that falls within the HFRA.

In response to Energy Safety's request, we are providing three separate maps identifying top risk within the HFRA:

1) Figure PG&E-6.4.1-1: WDRM Outputs Map;

2) Figure PG&E-6.4.1-2: WTRM Outputs Map; and

3) Figure PG&E-6.4.1-3: PSPS Risk Map.

The three maps below represent risk at the infrastructure level. Infrastructure level risk values from the risk models are a factor that is used to identify potential adjustments to the HFRA.[74]

Based on the Risk and WFC views from the WDRM v3 model, geographic locations with high wildfire risk and consequence outside the defined HFTD are identified for additional review and analysis as outlined in Section 6.4.1.2.

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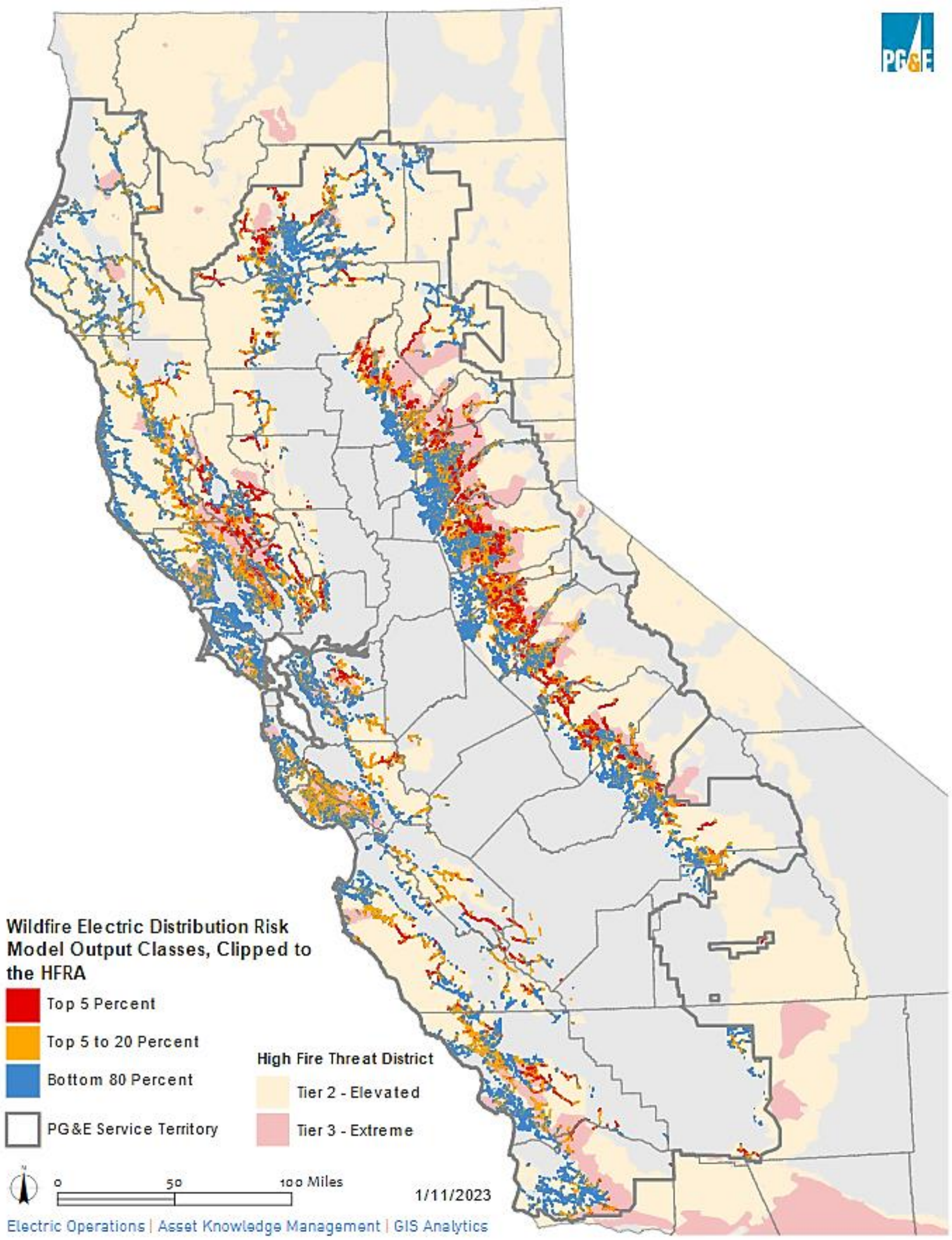
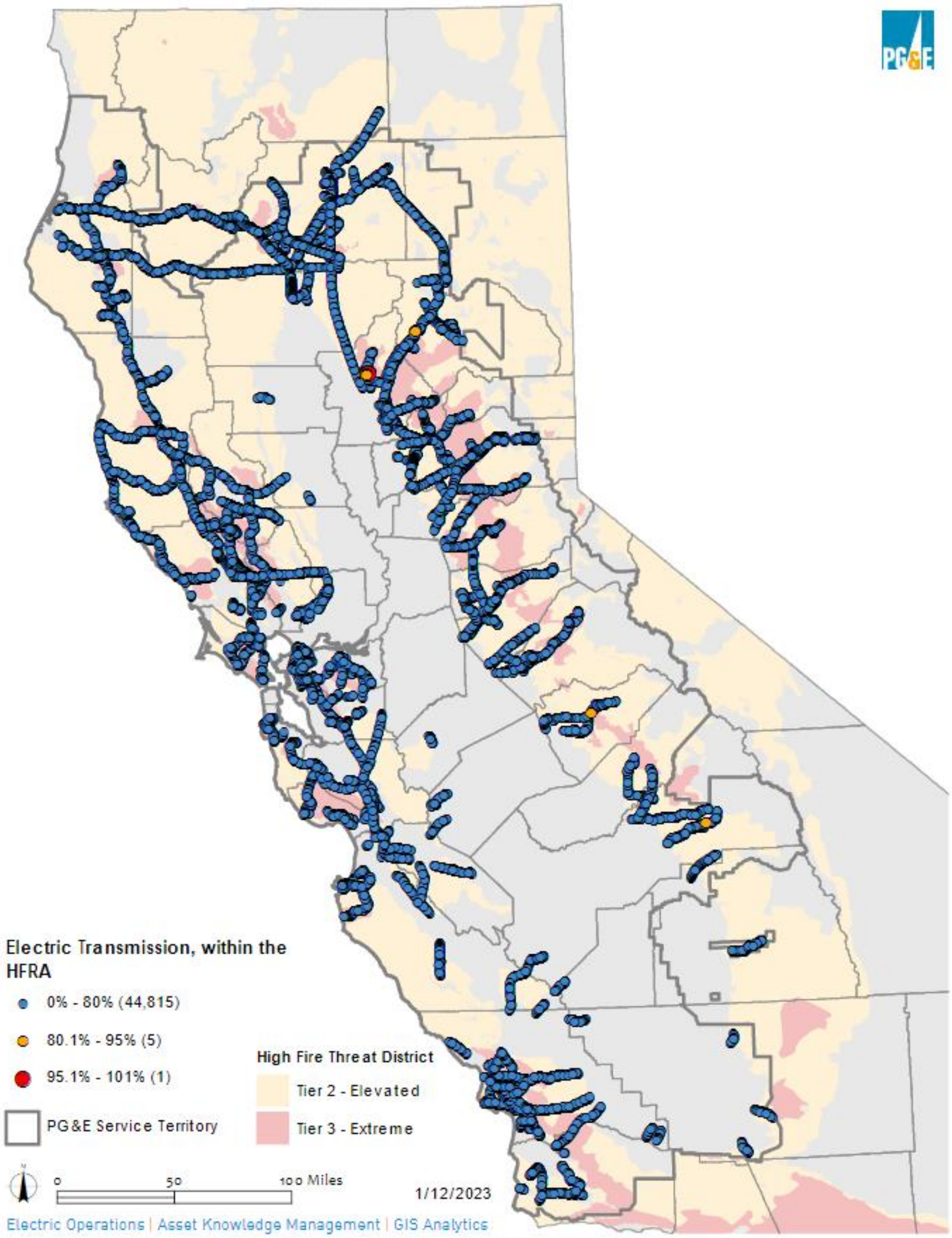
74 Please note, the risk maps (Figures PG&E 6.4.1-1, 6.4.1-2, and 6.4.1-3) contain data representing infrastructure with risk. Risk value outputs are specific to each risk model and are not necessarily comparable because of the individual methodologies used (see Section 6.1 for more details on the individual methodologies used).

**FIGURE PG&E-6.4.1-1:
WDRM OUTPUTS MAP**



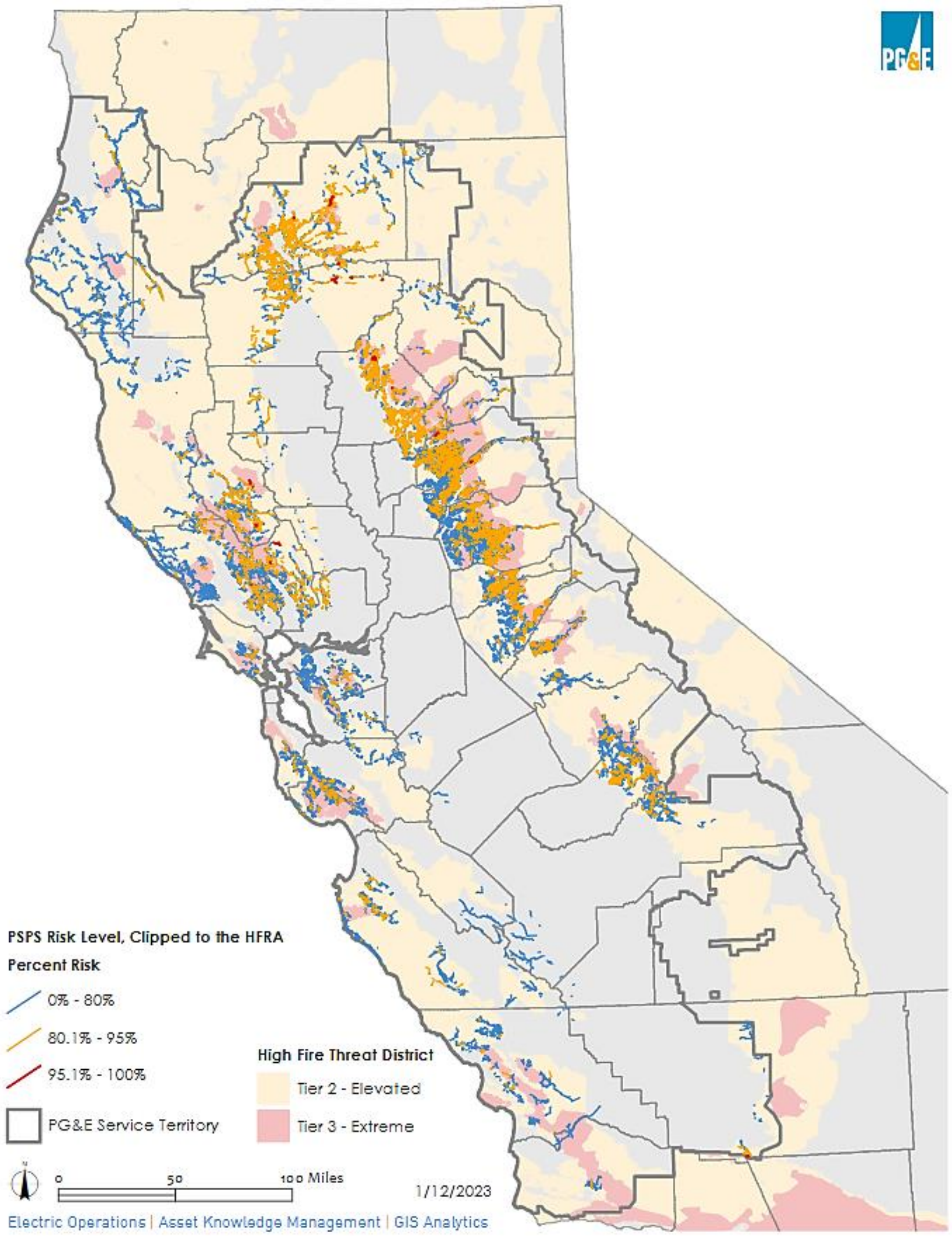
Note: For additional map viewing instructions, please refer to Appendix C.

FIGURE PG&E-6.4.1-2:
WTRM OUTPUTS MAP



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

**FIGURE PG&E-6.4.1-3:
PSPS RISK MAP**



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

6.4.1.2 Proposed Updates to 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. The electrical corporation must identify areas that its risk analysis indicates are at a higher risk than indicated in the current HFTD. The electrical corporation must also describe its process submitting proposed changes to the HFTD; to the CPUC, if such changes are desired; the electrical corporation need not conclude that the HFTD should be modified. Any proposed changes to the HFTD must be mapped in accordance with the requirements in the previous sub-section.

Consistent with Section 6.4.1.1, top-risk areas are defined as the areas corresponding to those 100 x 100 m pixels that intersect PG&E overhead electrical infrastructure locations and that are in the upper 20th percentile based on WDRM v3 risk scores. PG&E's HFRA, which is intended to inform the geographic scope of PSPS events (when combined with other spatiotemporal factors including, but not limited to wind, humidity, and fuels), identifies areas of PG&E service territory where we believe an ignition, during an offshore wind event, could lead to a catastrophic wildfire. This contrasts with Tier 2 and Tier 3 of the existing CPUC-approved HFTD, which is intended to identify areas where stricter fire safety regulations are to be applied, and does this by identifying areas with elevated risk and extreme risk, respectively (including likelihood and potential impacts on people and property), from wildfires associated with overhead utility power lines and overhead utility powerline facilities.[75] Top-risk areas within the HFRA ("top-risk/HFRA") is defined as the intersection of top risk areas and the HFRA.

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

- The mean risk score of top-risk/HFRA pixels (0.0071) is greater than the mean risk score for pixels in the HFTD (0.0043);
- While there is abundant overlap between the two areas, the overlap constitutes a much greater proportion of the top-risk/HFRA pixels, such that the top-risk/HFRA pixels are largely a subset of the pixels within the HFTD;
  - Of the 282,235 top-risk/HFRA pixels, 98 percent fall within the HFTD;
  - Of the 476,358 pixels within the HFTD, only 58 percent are also top-risk/HFRA pixels; and

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75 Decision (D.) 17-01-009 p. 25, broadly defines Tier 2 and Tier 3 of the CPUC's HFTD map as "Areas with elevated wildfire risk" and "Areas with extreme wildfire risk", respectively. A set of more explicit definitions is given in the Independent Review Team Final Report on the Production of the California Public Utilities Commission's Statewide Fire Map 2 (Nov. 21, 2017), p. 12, and reiterated in D.20-12-030, p. 2, and on the CPUC's Fire-Threat Maps and Fire-Safety Rulemaking webpage at: (https://www.cpuc.ca.gov/industries-and-topics/wildfires/fire-threat-maps-and-fire-safety-rulemaking) (as of Jan. 26, 2023).

- The 7,035 top-risk/HFRA pixels that are not in the HFTD are located throughout the service territory but are disproportionately clustered in two areas—the South Coast Range between King City and Coalinga (3,137 pixels), and the North Coast Range between Covelo and Arcata (1,891 pixels).

The attached geodatabase file[76] shows the areas within PG&E service territory that are top risk, but not in the HFTD. In addition, the geodatabase also contains a feature class that identifies areas within PG&E's service territory that are top consequence (areas corresponding to those 100 x 100 m pixels that intersect PG&E overhead electrical infrastructure locations and that are in the upper 20th percentile based on WDRM v3 consequence scores) but are not in the current HFTD. We are providing this second feature class because we believe that WFC is a more relevant metric than wildfire risk with which to evaluate areas for potential inclusion in the HFTD.

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 risk 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 (i.e., wildfire simulation modeling and risk assessment), expert judgement from internal and external stakeholders, and remote sensing data with 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 risk assessment using wildfire simulation 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 would submit those proposed modifications to the CPUC via a petition for modification to D.17-12-024. This petition for modification would, at a minimum, provide a unique identifier for each area proposed for modification, define the area's geographic boundaries, and present rationale for why PG&E believes the modification is warranted.

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76 For additional map viewing instructions, please refer to Appendix C.

6.4.2 Top Risk-Contributing Circuits/Segments

The electrical corporation must provide a summary table showing the highest-risk circuits, segments, or spans 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 the table below.

Note: Once populated, if this table is longer than two pages, the electrical corporation must append the table.

We determined our top risk contributing circuits/segments by assessing the two criteria set forth in the WMP Guidelines:

1) Individually contributes more than 1 percent of the total cumulative risk; and
2) Contributes to the top 5 percent of cumulative risk.

Given that PG&E manages most of our risk assessments and prioritization at the circuit segment level, PG&E identified 41 circuit segments that meet the above criteria. For context, PG&E has approximately 3,067 distribution circuits and 11,173 circuit segments across our system.[77]

Note, the top risk contributing circuit segments described here are a subset of the circuit segments PG&E manages and mitigates. PG&E considers other factors when determining if a circuit is high risk along with the risk scores generated by our risk models.

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[77] For additional details at the circuit segment level, please see workpaper included as Attachment 2023-03-27_PGE_2023_WMP_R1_Section 6.4.2_Atch01.

- Criteria 1: Based on the total overall utility risk from the WDRM + PSPS Consequence Model, PG&E has 0 circuit segments that cumulatively contribute more than 1 percent of the overall wildfire risk, regardless of circuit mileage (Table 6-5, Column “>1% Total Utility Risk”).

  Criteria 2: PG&E ranked our circuit segments from highest to lowest mean wildfire or ignition risk. We identified 41 circuit segments that fall within the top 5 percent of risk. By sorting in this method, the risk of a circuit segment is indifferent to the length of the circuit segment. For Table 6-5, we sorted the top 41 circuit segments by total overall risk score.

TABLE 6-5:
PG&E'S TOP RISK CIRCUIT SEGMENTS

Line No.	>1% Total Utility Risk	Top 5% Highest Risk Ranked by Mean	Circuit Segment Name	Wildfire Mean Risk Score[a]	HFTD Miles	Total Ignition Risk Score	Total PSPS Risk Score	Total Overall Risk Score	Top Risk Contributors[b]
1	FALSE	TRUE	INDIAN FLAT 1104CB	0.0393	13.80	118.47	–	118.47	Wildfire
2	FALSE	TRUE	BONNIE NOOK 1101CB	0.0295	17.80	85.79	5.49	91.28	Wildfire
3	FALSE	TRUE	ALLEGHANY 1102CB	0.0240	18.91	86.04	2.57	88.61	Wildfire
4	FALSE	TRUE	OAKHURST 110310140	0.0288	18.76	87.67	0.73	88.41	Wildfire
5	FALSE	TRUE	SILVERADO 2104515946	0.0254	19.06	80.74	4.86	85.60	Wildfire
6	FALSE	TRUE	HIGHLANDS 1102628	0.0261	15.78	75.42	0.16	75.58	Wildfire
7	FALSE	TRUE	UPPER LAKE 11011276	0.0250	12.29	67.22	–	67.22	Wildfire
8	FALSE	TRUE	MIDDLETOWN 110148212	0.0352	9.83	58.30	0.52	58.82	Wildfire
9	FALSE	TRUE	APPLE HILL 21026552	0.0258	13.02	55.76	1.35	57.11	Wildfire
10	FALSE	TRUE	NOTRE DAME 11042028	0.0245	11.39	49.53	0.57	50.10	Wildfire
11	FALSE	TRUE	CLAYTON 221296224	0.0341	10.18	46.82	0.47	47.28	Wildfire
12	FALSE	TRUE	ANTLER 11011384	0.0387	10.34	46.43	0.45	46.88	Wildfire
13	FALSE	TRUE	MONTICELLO 1101654	0.0268	8.30	42.09	0.97	43.06	Wildfire
14	FALSE	TRUE	BALCH NO 1 1101105414	0.0313	7.47	42.18	0.01	42.19	Wildfire
15	FALSE	TRUE	CURTIS 170356972	0.0250	8.42	40.94	0.16	41.10	Wildfire
16	FALSE	TRUE	MONTICELLO 1101630	0.0396	4.94	40.18	0.90	41.08	Wildfire
17	FALSE	TRUE	PINE GROVE 1101CB	0.0473	5.05	30.94	1.06	32.00	Wildfire
18	FALSE	TRUE	BUCKS CREEK 1101CB	0.0292	4.81	28.51	–	28.51	Wildfire
19	FALSE	TRUE	SILVERADO 2104646776	0.0343	5.69	22.93	3.66	26.59	Wildfire and PSPS
20	FALSE	TRUE	CALISTOGA 1102131531	0.0272	5.04	25.36	0.67	26.03	Wildfire
21	FALSE	TRUE	APPLE HILL 1104CB	0.0260	5.65	15.78	1.08	16.86	Wildfire
22	FALSE	TRUE	MIDDLETOWN 1101171414	0.0245	3.59	16.52	0.03	16.55	Wildfire

TABLE 6-5:
PG&E'S TOP RISK CIRCUIT SEGMENTS
(CONTINUED)

Line No.	>1% Total Utility Risk	Top 5% Highest Risk Ranked by Mean	Circuit Segment Name	Wildfire Mean Risk Score[(a)]	HFTD Miles	Total Ignition Risk Score	Total PSPS Risk Score	Total Overall Risk Score	Top Risk Contributors[(b)]
23	FALSE	TRUE	ELECTRA 1102CB	0.0264	2.60	13.93	0.00	13.93	Wildfire
24	FALSE	TRUE	ORO FINO 1102CB	0.0317	2.73	12.36	0.24	12.60	Wildfire
25	FALSE	TRUE	FRENCH GULCH 1101CB	0.0250	2.71	11.87	0.35	12.22	Wildfire
26	FALSE	TRUE	PARADISE 1103283794	0.0278	2.55	11.70	0.42	12.12	Wildfire
27	FALSE	TRUE	PARADISE 11061212	0.0270	2.37	8.97	3.08	12.04	Wildfire and PSPS
28	FALSE	TRUE	CRESTA 1101103126	0.0240	0.87	4.91	0.04	4.95	Wildfire
29	FALSE	TRUE	CRESTA 1101546650	0.0259	0.90	4.34	0.01	4.36	Wildfire
30	FALSE	TRUE	MONTICELLO 1101CB	0.0305	0.54	3.06	–	3.06	Wildfire
31	FALSE	TRUE	TIGER CREEK 0201CB	0.0409	0.40	2.30	0.00	2.30	Wildfire
32	FALSE	TRUE	INDIAN FLAT 11044440	0.0386	0.24	1.74	–	1.74	Wildfire
33	FALSE	TRUE	CALPINE 1144304	0.0684	0.05	1.70	0.01	1.71	Wildfire
34	FALSE	TRUE	APPLE HILL 2102CB	0.0901	0.17	1.38	0.05	1.43	Wildfire
35	FALSE	TRUE	MIDDLETOWN 1103CB	0.0270	0.05	1.09	–	1.09	Wildfire
36	FALSE	TRUE	PLACERVILLE 210658118	0.1047	0.11	0.89	0.01	0.90	Wildfire
37	FALSE	TRUE	BALCH NO 1 1101CB	0.0533	0.01	0.82	–	0.82	Wildfire
38	FALSE	TRUE	ALLEGHANY 11021101/2	0.0661	0.01	0.34	–	0.34	Wildfire
39	FALSE	TRUE	CALPINE 1144962	0.0244	0.04	0.21	–	0.21	Wildfire
40	FALSE	TRUE	CAMP EVERS 2105BL 2101	0.0449	0.00	0.09	–	0.09	Wildfire
41	FALSE	TRUE	MARIPOSA 210929360	0.0334	0.07	0.09	--	0.09	Wildfire

(a) Mean risk is the total risk score divided by the number of pixels.
(b) Top Risk Contributors are represented as either Wildfire, PSPS or both.

6.4.3 Other Key Metrics and Indicators

The electrical corporation must calculate, track, and present on several other key metrics of risk across its service territory. These include, but are not limited to the frequency of:

- *High Fire Potential Index (FPI): The electrical corporation must specify whether it calculates its own FPI or uses an external source, such as the USGS;*
- *Red Flag Warning (RFW); and*
- *High Wind Warning (HWW).*

For each metric, the frequency of its occurrence within each HFTD tier and the HFRA must be reported in the table below. The metric must be reported in number of Overhead Circuit Mile (OCM) days of occurrence normalized by circuit miles within that area type. For example, consider an electrical corporation with 1,000 OCM in HFTD Tier 3. If 100 of these OCM are under RFW for one day, and 10 of those OCM are under a RFW for an additional day, then the average RFW-OCM per OCM would be:

$$\frac{RFW\_OCM}{OCM} = \frac{(100 \times 1 + 10 \times 1)}{1000} = 0.1$$

This metric represents the average RFW-OCM experienced by an OCM within the electrical corporation's service territory within HFTD Tier 3. If the metric is continuous (such as FPI), the report should include a note stating the threshold used to select high values. Table 6-6 provides a template for reporting the required information.

Table 6-6 below is a summary of key metrics by statistical frequency for 2022 by quarter.

TABLE 6-6:
SUMMARY OF KEY METRICS BY STATISTICAL FREQUENCY FOR 2022 BY QUARTER

Metric	Non-HFTD	HFTD Tier 2	HFTD Tier 3	Areas Without a Heightened Risk of Fire (Non-Tiered)	Areas With a Heightened Risk of Fire (Tiered)
FPI-OCM/OCM					
2022 Q1	0.148	0.215	0.174	0.148	0.389
2022 Q2	26.552	28.093	23.746	26.552	51.839
2022 Q3	75.109	74.338	71.218	75.109	145.556
2022 Q4	20.397	22.062	20.037	20.397	42.099
RFW-OCM/OCM					
2022 Q1	0	0	0	0	0
2022 Q2	1.333	1.134	0.534	1.333	1.668
2022 Q3	0.004	0.082	0.048	0.004	0.13
2022 Q4	0	0.0002	0.027	0	0.0272
HWW-OCM/OCM					
2022 Q1	0	0	0	0	0
2022 Q2	0.000044	0.009	0.022	0.000044	0.031
2022 Q3	0	0	0	0	0
2022 Q4	0.007	0.042	0.049	0.007	0.091

The PG&E FPI is projected onto a rating (R) scale from R1 (low) – R5 (extreme). For this analysis, we chose R3 as the threshold.

6.5 Enterprise System for Risk Assessment

In this section, the electrical corporation must provide an overview of inputs to, operation of, and support for a centralized wildfire and PSPS risk assessment enterprise system. This overview must include discussion of:

- *The electrical corporation's database(s) used for storage of risk assessment data;*
- *The electrical corporation's internal documentation of its database(s);*
- *Integration with systems in other lines of business (LOB);*
- *The internal procedures for updating the enterprise system including database(s); and*
- *Any changes to the initiative since the last WMP submission and a brief explanation as to why those changes were made. Include any planned improvements or updates to the initiative and the timeline for implementation.*

Databases Used to Store Risk Assessment Data

Below we describe how we store our risk assessment data for different risk models.

Internal Documentation

The Foundry tables are documented in place within Foundry with the schemas determined by the tables themselves, and the data flows documented in the built-in Data Lineage tooling. Data column descriptions, derivation, and limitations are generally documented separately, as declared for each of the individual models. Some of that data is also available through Collibra depending on the maturity of the models.

Integrating with Other LOBs

Migrating our data into Foundry, a centralized platform, is how we are integrating risk data across our different Functional Areas (formerly called "Lines of Business" within PG&E).

Updating the Enterprise System

Foundry itself is updated by Palantir on an ongoing basis as improvements are made to the system. Existing projects are configuration controlled to specific historical versions of the Foundry APIs (Application Programming Interface) and associated libraries but will be automatically upgraded if the development team responsible for the project accepts any of the automatically generated upgrade patches that will be submitted by the system. At that point, the update will be available for promotion to the production (master) branch, but may need to go through testing, depending on the project.

Changes Since the Last WMP

This initiative is new in the 2023 WMP. The work described above occurred after we submitted our 2022 WMP.

ERM Bow-Tie Models

PG&E's risk assessment input data for bowtie-based ERM is stored in PG&E's Enterprise Microsoft SharePoint.[78] We also store our wildfire risk assessment data related to EO and other service areas in SharePoint as well.

All risk assessment output data from bowtie-based ERMs is uploaded and stored in Palantir Foundry. This applies to bowtie models for risks from all Functional Areas in the Corporate Risk Register. Palantir Foundry is an enterprise platform for data-driven operations and decision making.

In 2023, PG&E is planning to migrate ERM into Foundry[79] to integrate planning-level risk assessment data (from models such as the WDRM and WTRM) and use Foundry as a centralized enterprise system to store standardized inputs and outputs of risks evaluated using ERM. The migrated ERM will be connected to risk reduction and RSE calculations in Foundry, providing one cohesive system for performing risk assessment for bowtie-based ERMs.

Transmission OA

Data tables that form the inputs and outputs of the PSPS related OA models are archived daily in Amazon Web Services (AWS) Redshift (2019-2021) and in AWS S3 (2022-present). The OA S3 datasets are self-describing parquet files. Detailed column definitions and derivations are maintained in a separate data dictionary document as an Excel file and stored in SharePoint. Documentation of the model logic is stored in SharePoint as well.

Data from OA feeds primarily into the OA Dashboard and is also delivered to Meteorology for mapping the FPI, and to our external consultant for ongoing research and development.

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78 SharePoint is a collaboration site where team can share files, data, and other resources.

79 Foundry is a data analytics platform with support for Structured Query Language (SQL) implemented on top of the open-source Apache Spark distributed computer platform but is not a database in the common sense of the term. Data storage is in flat files, primarily stored as parquet (column compressed storage) files. Input data is obtained from various systems of record including Meteorology AWS S3, Electric Transmission Geographic Information System, Electric Distribution Geographic Information System, Landbase Geographic Information System, and SAP, as well as other flat files in common use with Asset Strategy and manually uploaded to Foundry. Risk model outputs are stored in Foundry or Analytics Rapid Application Development AWS S3 buckets for archival reference. For live use the data are visualized within Foundry using platform-supplied data visualization and application building tools. May be accessed here: https://www.palantir.com/platforms/foundry/.

Data flows are managed within Palantir Foundry from the best currently available datasets. Major model changes are done prior to fire season and validated through delta analysis by Meteorology, Asset Strategy, and Exponent prior to authorization for production use during fire season. The previous year model is maintained in an operational state until the new model has passed delta analysis approval.

Distribution Ignition Producing Winds (IPW)

The IPW model data is stored in a PostgreSQL database on our computing environment in the AWS cloud.

We have internal documentation of the system architecture, model construction and disaster recovery.

The IPW model data is integrated into our PSPS processes and Foundry database system. The Foundry platform is used for PSPS.

Internal procedures include standard development practices, which involve our tiered computing environment. For example, we develop new code, software and updates in our development environment, test in QA, and deploy in production.

Wildfire Transmission Risk Model/Transmission Composite Model (WTRM/TCM)

Data Table inputs and outputs for the WTRM (TCM) model are located in Palantir Foundry and retained for the standard retention period for Foundry datasets where data is eligible for deletion once five newer datasets exist. Data schema and column definitions are maintained within Foundry. Documentation of the model logic is stored in SharePoint.

WTRM inputs are sent to our consultant for visualization using PowerBI, which is then forwarded to Asset Strategy and archived in SharePoint for transmission asset planning.

Data flows are managed within Palantir Foundry and inputs are mostly identical to the data that flows into OA, with extensions for new models that have not yet been approved or implemented into the PSPS production OA release. Changes to the TCM models are developed and tested by our consulting, combining SME expertise from other organizations as new risk sub-models are added.

Wildfire Distribution Risk Model (WDRM)

Data Table live inputs and outputs for WDRM model are stored in Palantir Foundry. Archival inputs and outputs for historical versions of the model are serialized as self-describing parquet files and stored in a designated Foundry Data frame that holds the full history of the datasets.

No other production systems are downstream of WDRM.

Data flows are managed within Palantir Foundry, which is also used to store archival backups of completed model runs. The model run is completed once upon completion of User Acceptance Testing (UAT) and then the model outputs are archived.

WDRM presents data using Foundry Slate, Contour, Maps, and Workshop. UAT is done on the system as a whole and the production output is maintained for reference by the asset planning team until the next production version has completed UAT, which occurs on an annual basis.

PSPS Consequence Model

Data Table live inputs and outputs for PSPS Consequence model are stored in Palantir Foundry. Archival inputs and outputs for historical versions of the model are serialized as self-describing parquet files and stored in a designated Foundry Data frame that holds the full history of the datasets.

6.6 Quality Assurance and Control

6.6.1 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 Review Triggers: The electrical corporation's procedures for conducting independent reviews of data collection and risk models.*
- *Additional Review: The electrical corporation's internal processes and 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.*
- *Routine Review Schedule: The electrical corporation's routine review schedule.*

The electrical corporation must enter each accepted recommendation from independent review into the action tracking system for resolution (assignment of responsibility, development of technical plan, schedule for development and deployment, etc.) in accordance with the requirements discussed in Section 11.

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 6.6.2, these reviews are conducted in the first quarter of each year as part of the final preparation of the model for approval and use. The external reviews are conducted by an independent third-party to assess the risk framework and modeling approach, model fit for developing wildfire mitigation plans, improvements over previous models, and model application within company planning processes. Along with these assessments, a list of improvement areas are identified for integration in to the next model development objectives.

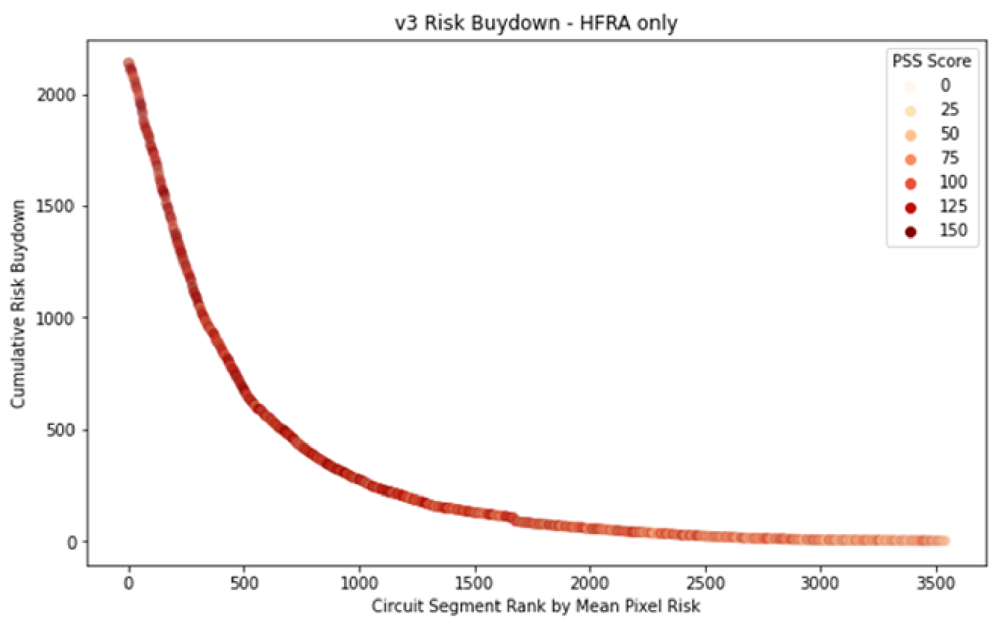
Additional Review: As outlined in Figure PG&E-6.6.2-1 risk models are reviewed and approved for use by the Wildfire Risk Governance Steering Committee (WRGSC). As part of this step, third-party reviews of data, data collection, and risk models may be initiated outside of the routinely scheduled reviews associated with model validation prior to WRGSC review and approval.

Results, Recommendations, and Disposition

PG&E's PSS team conducted a qualitative, circuit-based risk assessment review of the outputs from the WDRM v3. This qualitative assessment is based on their collective 300+ years of fire experience. Most of the PSS team members had a previous career with CAL FIRE or other fire agencies. The PSS assessment assigned a qualitative score of 0, 5, 15, or 30 in each of five categories, focused not on ignition probabilities but on factors that will impact the ability to manage a fire based on their unique history in fighting fires in these locations. These categories were: Fire History, Ingress/Egress Impacts, Resistance to Control, Community Risk Factors, and Other Unique Local Factors. These five values are then combined to achieve a total value for all circuits in the HFTD and HFRA.

These qualitative values were compared with the System Hardening Risk Composite scores by assembling the PSS assessment along the WDRM v3 risk buy-down curve. As circuits with higher PSS values tend toward the upper end of the risk buy-down curve the PSS assessment and WDRM v3 correlate well, particularly in the first half of the curve.

FIGURE PG&E-6.6.1-1:
HFRA WDRM v3 SYSTEM HARDENING BUYDOWN



<u>E3 Review</u>

E3—Energy, Environment and Economics—conducted an independent, third-party review of the WDRM v3.[80] The objective of the review was three-fold:

- Review the suitability and applications of consequence data in the modelling framework;

80 Energy and Environmental Economics, E3 Review of PG&E's Wildfire Risk Model Version 3 (E3 Review) (May 2022). A copy of this E3 report is included as Attachment 2023-03-27_PGE_2023_WMP_R0_Section 6.6.1_Atch01.

- Review the specific use of the Risk Model Information in each of its operations areas; and
- Describe potential future uses of v3 and longer-term multi-year wildfire planning models.

This was a deliberate expansion of the objective for the E3 review of the WDRM v2 model which was to determine whether the model was 'fit for purpose.'

As result of the review E3 concluded the following:

> PG&E has made substantial progress in transforming its model from one that was primarily used to validate mitigation measures chosen by its subject matter experts (SME) within high fire zone areas to a model that can be used to supplement and prioritize the targeting of mitigation measures across its entire service territory.[81] The construct of v3 appears to be consistent with their commitment in their WMP to refocus mitigation work to achieve a target where 80 percent of their work is focused on mitigating the risk of the highest 20 percent of identified line segments.[82]
>
> PG&E has made a substantial effort to incorporate feedback from the CPUC, stakeholders, E3 and its internal users to update the WDRM between versions 2 and 3. The updates made represent real improvements in several critical areas. From E3's review, the modeling team includes a group of highly skilled professionals from inside and outside of PG&E. The model is leveraging the best available data and methods to prioritize risk levels by geographic area and ignition type allowing for evidence-based decision-making. This model represents an improvement from v2.[83]
>
> Most of modeling limitations are driven by limitations in data and resources which are difficult for the modeling team to directly solve.[84]

In line with the third objective to 'Describe potential future uses of v3 and longer-term multi-year wildfire planning models,' E3 identified several items for future improvement of the WDRM in future iterations:

- While PG&E should be commended for its rapid development of a model that shows substantial promise to increase the effectiveness of their mitigation work, our recommendations focus on a few existing gaps:
- Standardizing and documenting the relationship between the model and subject matter experts;

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81 E3 Review, p. 4 (emphasis removed).

82 E3 Review, p. 4.

83 E3 Review, p. 11.

84 E3 Review, p. 11.

- The transparency and validity of the consequence portion of the model;
- Establishing a data quality control process;
- Establishing a roadmap for model direction;
- Exploring potential further use cases of the model; and
- Coordination of PG&E's process with broader State-wide wildfire planning."[85]

E3 also assessed PG&E's progress on the recommendations from the WDRM v2 validation report. E3 found that the WDRM v3 addressed many of these and recommended continued progress on three remaining items. These three are highlighted in the WDRM v3 validation report for continued progress: (1) a more detailed modeling roadmap; (2) tighter coordination with SME input: and (3) and transparency of the WFC data.[86] Information about PG&E's progress against each of the three recommendations for continued progress is provided in response to ACI PG&E-22-07.

Routine Review Schedule:

The risk model development process includes both internal and external reviews. In alignment with the model's development schedule outlined in Section 6.6.2, these reviews are conducted in the first quarter of each year. The internal reviews are conducted by a range of internal parties including, Enterprise Risk, Internal Audit, and Public Safety Specialist (PSS) teams. Identified areas for improvement are either addressed before model approval or added to the model development objectives for the next model.

85 E3 Review, p. 4.

86 E3 Review, pp. 12-14.

6.6.2 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:

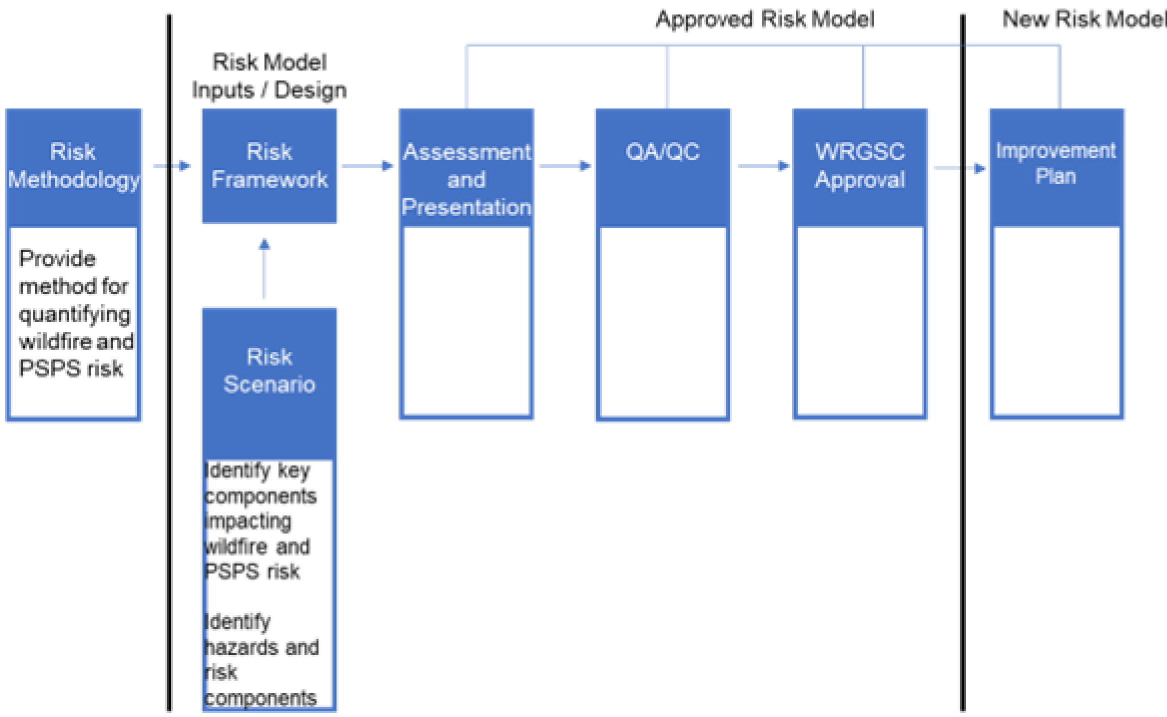
- *Modularization: The electrical corporation must report on: the degree to which its software architecture is sufficiently modular to track and control changes and enhancements over time. At a minimum, the electrical corporation must report if it has separate modules to evaluate each of the following:*
  - *Weather analysis;*
  - *Fire behavior analysis;*
  - *Seasonal vegetation analysis; and*
  - *Equipment failure.*
- *Reanalysis: 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.*
- *Version Control: The electrical corporation must report on how in conforms to industry standard practices in version controlling its risk model and sub-models. At a minimum, the electrical corporation is expected to 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;*
  - *Procedures for updating technical, verification, and validation documentation.*

Model Development Process

Based on the Risk Framework outlined in Section 6.2, the model development process follows a modularized and discrete set of repeatable steps outlined in Figure PG&E-6.6.2-1 below. The intent of this formalized process is to support model fidelity, transparency, and repeatability. Beginning with the first step, Risk Methodology, through to developing improvement plans, steps are modularized and archived.

The Risk Methodology step outlines the model scope, objectives, and design scenarios discussed in Section 6.3. Next, the individual risk models are developed. The development of these models is an iterative process up to model approval. The draft models are presented for internal review to workplan development teams and independent third parties for validation. The model development process culminates with presentation to the WRGSC for final approval. With WRGSC approval, the models can then be used to develop mitigation workplans.

FIGURE PG&E-6.6.2-1:
RISK MODEL DEVELOPMENT



For planning models such as the WDRM and WTRM the model components (probability of ignition, wildfire consequence) shown in the Risk Framework in Section 6.2 are discrete but automated software modules. Each module is generated by productionalized 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.

WDRM Model Development Process

The WDRM v3 is implemented primarily in Python, using a sequence of interconnected configurable computation tasks to complete a model run, store its results, and report out metrics of model performance. The key modeling steps are described in the following table. Unless otherwise noted, 25 percent of training data is withheld from each model fit to be used to compute out of sample predictive performance metrics.

TABLE PG&E-6.6.2-1:
WDRM MODEL DEVELOPMENT PROCESS

WDRM Model Development Process	
Step	**Description**
1	Define the target set, which is the set of all events of type outage, ignition, and PSPS hazards and damages that are used to train the sub-models that comprise the WDRM v3. The target set is limited to events that occurred during the fire season months of June through November between 2015 and 2021 and is filtered to exclude events involving underground equipment, where outages were caused by wildfire or planned by the company, and the small portion of events without valid locations.
2	Identify subsets of the target set that share cause, sub-cause, and type of equipment involved. The Subset Manager divides the target set into 17 non-overlapping subsets that span the target set.
3	Prepare the model covariate data.
4	Train the probability of ignition given an outage model using target set data.
5	Predict P(outage) and P(ignition|outage) for each subset, yielding estimates of P(ignition).
6	Determine the mitigation potential from various measures applied to each subset's risk.
7	Composite probabilities and risks from individual subsets into broader categories used for planning purposes.

Modularization

In steps 1 and 2 the WDRM is designed to employ multiple layers of modularization to manage changes and enhancements. As outlined in Section 6.2, the WDRM v3 is comprised of two core modules: the Consequence model and the Probability model (see Figure PG&E 6.2.1-2). The Probability model is further modularized into several models: a Probability of Ignition (given Outage) model and 17 Probability of Outage subset models (see Table PG&E 6.2.2-1).

The Consequence model is constructed from annually generated weather and fire behavior analysis datasets. The Probability models, depending on the subset, are built using annually generated datasets for weather, vegetation, equipment failures, equipment geo-location, and other characteristic values. 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 Foundry.

Reanalysis

In Step 6, the WDRM model is released to end-users for annual planning as a data-cube of seasonal probability, consequence, and risk results through a Foundry-based user interface. The WDRM is not directly executable by an end-user. However, all code and datasets used to generate a WDRM version release are archived such that the results could be regenerated if necessary.

Version Control

Throughout the model development steps the WDRM uses multiple controls. Post-release of WDRM v3, an internal PG&E audit team investigated the version and control processes used for compliance in alignment with PG&E IT standards relating to version control.

The audit reported two medium-level issues for improvement with IT processes related to cloud services and user management and reported no operational process issues.

6.7 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:

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

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

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

Table 6-7 provides an example of the minimum acceptable level of information

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

- *<u>Problem Statement</u>: Description of the current state of the problem to be addressed;*
- *<u>Planned Improvement</u>: Discussion of the planned improvement, including any new/novel strategies to be developed and the timeline for their completion;*
- *<u>Anticipated Benefit</u>: Detailed description of the anticipated benefit and any other impacts of the proposed improvement;*
- *<u>Region Prioritization (Where Relevant)</u>: 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 6-7:
PG&E'S RISK ASSESSMENT IMPROVEMENT PLAN

Key Risk Assessment Area	Proposed Improvement	Type of Improvement	Expected Value Add	Timeframe and Key Milestones
RA-01, Risk Assessment Methodology	Incorporate ingress/fire suppression (Terrain Difficulty Index (TDI)) attributes into the WFC Model.	Technical	Improved representation of the ability of fire responders to suppress an active wildfire.	By end of 2023
RA-02, Risk Assessment Methodology	Incorporate egress attributes into the WFC Model.	Technical	Improved representation of the ability of a community to safely evacuate from and active wildfire.	By end of 2023
RA-03, Risk Assessment Methodology	Evaluate an approach to incorporate the community vulnerability attribute(s) (e.g., AFN, Economic disadvantaged zones, Critical Facilities) into the wildfire and PSPS consequence models.	Technical	Improved representation of wildfire risk to vulnerable communities.	By the end of 2023, Evaluate an approach to incorporate community vulnerability attributes (AFN, Economic disadvantaged zones, Critical Facilities) into the WFC Model.
RA-04, Risk Assessment Methodology	Incorporate community vulnerability attributes (e.g., AFN, Economic disadvantaged zones, Critical Facilities) into the wildfire and PSPS consequence models, if deemed appropriate, based on the evaluation completed as part of RA-03.	Technical	Improved representation of wildfire risk to vulnerable communities.	By the end of 2024, Incorporate, if deemed appropriate through the evaluation.
RA-05, Risk Assessment Methodology	Incorporate risk reduction calculations based on location-specific risk and mitigation alternatives tied directly to the Wildfire Risk Models, as well as incorporate requirements defined in the Rulemaking (R.) 20-07-013 Risk Order Instituting Rulemaking (OIR) Phase II Decision.	Technical	Quantification of risk reduction values at specific locations to drive mitigation alternative considerations	By end of 2024

TABLE 6-7:
PG&E'S RISK ASSESSMENT IMPROVEMENT PLAN
(CONTINUED)

Key Risk Assessment Area	Proposed Improvement	Type of Improvement	Expected Value Add	Timeframe and Key Milestones
RE-01, Risk Event Tracking	Review and reattribute ~3,100 Historic CPUC-reportable Ignitions that occurred prior the establishment of PG&E's Enhanced Ignition Analysis (EIA) program in 2021.	Technical	Improved completeness and quality of reportable ignition dataset.	By end of 2023
DB-01, Design Basis	Conduct an analysis of long-term future fuel forecasts for use in planning models.	Technical	Potential update and refinement of representation of future fuels	By end of 2024
RP-01, Risk Presentation	Update presentation of spatial view of the WDRM and WTRM.	Programmatic	Improved application of risk models in developing wildfire mitigation plans.	By end of 2024

Improvement Area Narratives

Risk Assessment Methodology –1: Incorporate Ingress/Fire Suppression (TDI) Attributes into the WFC Model.

Problem Statement:

The WFC Model does not explicitly account for fire suppression. While the use of VIIRS data to develop the WFC Model does include suppression impacts, Technosylva fire simulations do not account for suppression when reporting on fire behavior or extent. Without explicitly accounting for suppression, locations where fires could be easily suppressed could be ranked alongside locations where suppression might be more difficult.

The challenge to explicitly modeling suppression is that data is needed that highlights the difference between suppressed and unsuppressed wildfires. The missing piece from historical wildfire data is specifically the outcome of unsuppressed fires.

Planned Improvement

An approach has been developed for a suppression adjustment factor that will be implemented in the next version of WFC Model.

This approach divides the modeling of suppression into two components:

1) Constraining the footprint of a fire (acres burned); and

2) Protecting structures in or near a fire (buildings lost).

At this point, a methodology for estimating the protection structures in or near a fire has been developed. This is accomplished by employing the Technosylva TDI to calibrate an estimate of structures destroyed, in comparison with the total number of structures within a fire footprint, as an indication of suppression failure. Technosylva RAVE and/or WRRM simulations are used to estimate the structures that would be destroyed for an unsuppressed ignition.

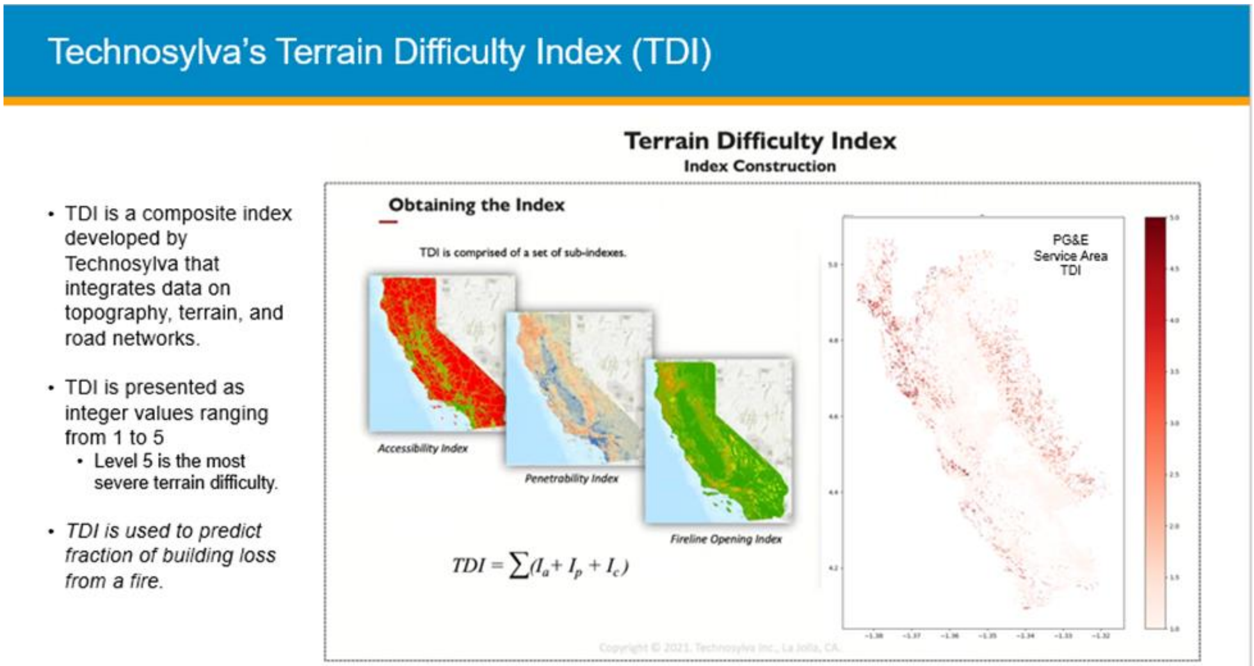
Consistent with past risk model development schedules, the next risk models will be validated and approved during the first quarter of 2023 to develop wildfire mitigation workplans for 2024. Work will also continue with the Energy Safety Risk Model Work Group to improve the modeling of both the acres burned and buildings lost portion of fire suppression estimation.

Anticipated Benefit

As outlined in the problem statement, it is anticipated that this suppression adjustment will raise the assessed WFC of locations that are more remote and difficult to access by fire resources. Similarly, locations which are easily accessed by fire resources available to contain and suppress a fire will have lower WFC than in previous models.

The Technosylva TDI is a composite index that incorporates spatial estimates of accessibility, penetrability, and the ability of fire resources to establish a fire line (Figure PG&E-6.7-1).

FIGURE PG&E-6.7-1:
TECHNOSYLVA'S TERRAIN DIFFICULTY INDEX



Risk Assessment Methodology – 2: Incorporate Egress Attributes into the WFC Model.

Problem Statement:

The WFC Model does not explicitly account for egress factors. The challenge to explicating modeling egress is the lack of observable evacuation data. Modeling through evacuation simulations that include traffic models are susceptible to many non-linear factors. PG&E has worked collaboratively with the University of California, Los Angeles Garrick Risk Institute to develop an egress simulation model. A detailed, bottom-up application of this model will require extensive tuning for each individual community. This will be an area of further study while an initial adjustment factor is developed for the WFC Model.

It is anticipated that directly accounting for egress will improve the identification of communities for which evacuating from the path of a potential wildfire could be more challenging. This will potentially raise the assessed WFC of these communities in the WFC Model.

Planned Improvement

An approach has been developed for an egress adjustment factor that will be implemented in the next version of WFC Model.

Despite the challenges listed above, the failures of evacuations are observable through CAL FIRE fatality counts and building destructions. Our current approach quantifies data relationships that predict these fatalities using variables derived from a range of data such as road access, resident mobility, and other AFN data.

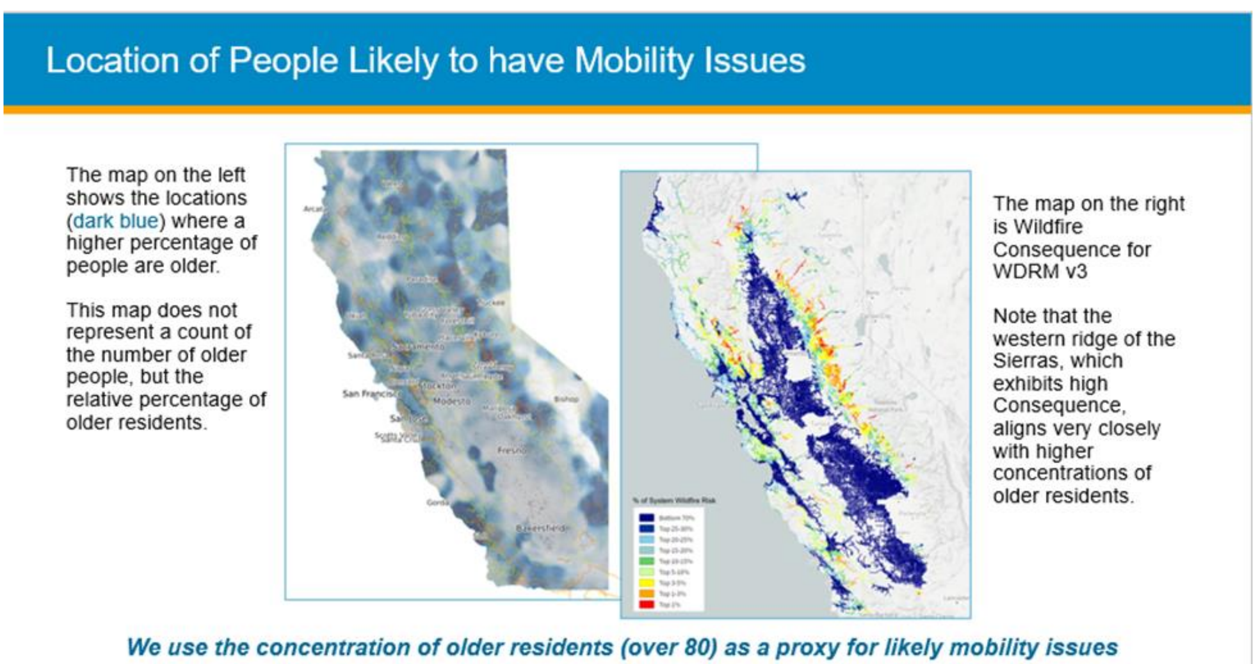
Consistent with past risk model development schedules, the next risk models will be validated and approved during the first quarter of 2023 in order to develop wildfire mitigation workplans for 2024. Work will also continue with the Energy Safety Risk Model Working Group to further investigate and develop models that represent communities for which egress may be a challenge.

Anticipated Benefit

Based on initial modeling work a correlation with communities with high concentrations of residents over the age of 80. Using this as a proxy for mobility issues, communities most likely to experience more challenge with egress from a wildfire can be seen in the comparison maps below (Figure PG&E-6.7-2). Work to refine this relationship along with seeking correlations with other potentially influential data will continue.

As a result, WFC values for locations with higher egress challenges will likely be higher than in previous models.

FIGURE PG&E-6.7-2:
LOCATION OF PEOPLE LIKELY TO HAVE MOBILITY ISSUES



Risk Assessment Methodology – 3: Evaluate an Approach to Incorporate the Community Vulnerability Attribute(s) (e.g., AFN, Economic Disadvantaged Zones, Critical Facilities) Into the Wildfire and PSPS Consequence Models.

AND

Risk Assessment Methodology – 4: Incorporate Community Vulnerability Attributes (e.g., AFN, Economic Disadvantaged Zones, Critical Facilities) into the Wildfire and PSPS Consequence Models, if Deemed Appropriate, Based on the Evaluation Completed as Part of RA-03

Problem Statement

The WFC Model does not explicitly account for attributes related to vulnerable communities. Currently, PG&E's PSPS processes and modeling account for vulnerable communities in that they identify vulnerable communities so that we can provide outreach and services to minimize the impact of the potential planned PSPS outage on them. The challenge is to improve how we represent the impacts of wildfire on vulnerable communities in the wildfire risk planning models.

The current approach we are exploring is to seek appropriate modifiers to the MAVF, or future Cost Benefit calculations, that account for the non-linear impacts on vulnerable communities across a range of factors.

Planned Improvement

We anticipate that representing vulnerable communities more accurately will improve the representation of wildfire risk due to demographic information. Specifically, if a geographic location has a higher percentage of an AFN demographic characteristic the risk values in that location could represent the increased impact and shift prioritization of work accordingly.

Interestingly, the work on egress provides an example of an additional possible method for how to incorporate data representing vulnerable communities. By evaluating AFN data such as age in the egress model a correlation with egress challenges was identified. While this is likely an indicator of age representing mobility capabilities it effectively identifies and represents an increased risk at a community level. Further exploration for similar correlations across the risk models will be part of this effort.

While some vulnerable community factors, such as those discussed with the egress model, may be included in the next model, the broader development and ongoing evaluation of these features will be developed during 2023. During this time, PG&E will also collaborate with other utilities and interested parties as part of the Energy Safety Risk Model Working Group on this topic as part of the 2023 meeting agenda topics. This approach is then planned for model application during 2024.

Anticipated Benefit

As mentioned above, we anticipate that incorporating more data representing vulnerable communities will improve the representation of wildfire risk at the community level.

Risk Assessment Methodology – 5: Incorporate Risk Reduction Calculations Based on Location-Specific Risk and Mitigation Alternatives Tied Directly to the Wildfire Risk Models, as well as Incorporate Requirements Defined in the R.20-07-013 Risk OIR Phase II Decision.

Problem Statement

The Wildfire Risk Models do not directly output location specific risk mitigation alternatives for recommendation to the user. Each mitigation alternative provides a different level of risk effectiveness, as well as a cost to implement. This functionality would allow a user to compare Risk Spend Efficiency across mitigation solutions at specific locations instead of at the programmatic level. In the latest R.20-07-013 Risk OIR Phase II Decision, Risk Spend Efficiency has been changed to a Benefit-Cost Analysis. Future Wildfire Risk Models need to directly output Benefit-Cost Analysis for risk mitigation alternatives.

Planned Improvement

Planned development would address all R.20-07-013 requirements. In addition to this development, Risk Models would leverage location specific effectiveness, as well as cost impacts, based on environmental conditions such as vegetation and terrain. This implementation will be embedded in the wildfire risk model development cycle and will be included in PG&E's 2024 RAMP Filing.

Anticipated Benefit

This allows a user to make informed mitigation alternative tradeoffs. For example, while undergrounding is one of the most risk-reducing mitigation solutions, it is possible based on the terrain and lack of vegetation, having covered conductor overhead system hardening may be a more cost-beneficial solution. The result of this is a portfolio that balances risk reduction and resource allocations.

Risk Event Tracking – 01: Review and Reattribute Historic Ignitions Record

Problem Statement

In 2021, PG&E initiated the Enhanced Ignition Analysis (EIA) program consisting of experts in Wildfire Risk, Asset Strategy, Applied Technology Services, Vegetation Management, Standards, and Asset Engineering teams to investigate CPUC Reportable ignition events and collect structured data associated with those events to improve tracking and trending.

PG&E's data for historic ignition events prior to this program—consisting of ~3,100 CPUC Reportable ignitions, which represent most of PG&E's ignition record—were not attributed to the same level of detail as our current practices. This impacts accurate tracking and trending of fires prior to the EIA program.

Planned Improvement

PG&E investigators will re-analyze our historic reportable ignition record to verify accuracy of geospatial datapoints, causal-chain fields, and modernize the data schema for the ~3,100 historic CPUC reportable events occurring prior to 2021.

Anticipated Benefits

Through this effort, PG&E expects to generate more robust data for our CPUC reportable ignitions recorded before 2021. This will help us improve our ability to trend PG&E's ignition record and provide greater insight into past events.

Design Basis -01: Conduct study of long-term future fuels forecast

Problem Statement

Currently, PG&E employs a 2030 forecast fuels layer that represents current fire burn scars with full regrowth of fuels. This future fuels forecast does not attempt to predict changes in fuels due to climate change, land use, or other externalities.

Planned Improvement

PG&E will coordinate and conduct a study of potential long-term future fuel cases that take into account the impacts of climate change, land use, and other externalities. This study will consider and use input from currently available climate studies and external state agencies.

Anticipated Benefits

The resulting study will inform both a range of potential future long-term fuel forecasts that could be used for sensitivity analysis as well as adjustments to the long-term fuel data used in the wildfire risk planning models.

Risk Presentation -01: Update presentation of spatial view of the WDRM and WTRM

Problem Statement

As identified by the independent third-party validation of the WDRM, post model steps to develop mitigation workplans present an opportunity for model improvement to incorporate current post-model steps. The improvement of providing spatial views that more directly tie to workplan units is one such example.

Planned Improvement

Based on feedback from workplan development teams, identify and develop improvements to current spatial views of the wildfire risk models.

Anticipated Benefits

Improvements to spatial views of the risk models that more directly tie to wildfire mitigation plans will improve the application of risk models and the transparency of workplan development.

PACIFIC GAS AND ELECTRIC COMPANY

2023-2025 WILDFIRE MITIGATION PLAN

SECTION 7

WILDFIRE MITIGATION STRATEGY DEVELOPMENT

7. Wildfire Mitigation Strategy Development

In this section of the Wildfire Mitigation Plan (WMP), the electrical corporation must provide a high-level overview of its risk evaluation and process for deciding on a portfolio of mitigation initiatives to achieve maximum feasible[87] *risk reduction and that meet the goal(s) and plan objectives stated in Sections 4.1-4.2, and wildfire mitigation strategy for 2023 2025. Sections 7.1 and 7.2 below provide detailed instructions.*

7.1 Risk Evaluation

7.1.1 Approach

In this section of the WMP, the electrical corporation must provide a brief narrative of its risk evaluation approach, based on the risk analysis outcomes presented in Section 6, to help inform the development of a wildfire mitigation strategy that meets the goal(s) and plan objectives stated in Sections 4.1-4.2.

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.

The following is an example of this description:

The risk evaluation approach in this WMP is designed to meet a range of industry-recognized standards (e.g., International Organization for Standardization 31000), best practices, and research[88] *to determine a wildfire and Public Safety Power Shutoff (PSPS) risk mitigation strategy. The intent is to use this approach to help inform [electrical corporation]'s development of a portfolio of wildfire mitigation initiatives and activities that meet the goals and objectives stated in Sections 4.1-4.2. Therefore, the general risk evaluation approach consists of the following:*

- *Identify key stakeholder groups, decision-making roles and responsibilities, and engagement process.*
- *Identify risk evaluation criteria based on the balance of various performance goals. Apply these criteria to monitor the effectiveness of the electrical corporation's WMP in achieving its identified goals and objectives.*
- *Evaluate wildfire and PSPS risks and risk components described in Section 4 against the risk evaluation criteria, considering both potential positive and potential negative outcomes. Apply the results from the evaluation of wildfire and PSPS risks within [electrical corporation]'s service territory within a risk-informed*

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

88 *Aven, Foundations of Risk Analysis (2nd ed. 2012, John Wiley and Sons, West Sussex, United Kingdom).*

decision-making process to develop prioritized areas where mitigation initiatives are necessary.

- *Identify a portfolio of wildfire mitigation initiatives and activities, prioritized by risk. Identify and characterize potential mitigation approaches for each.*
- *Perform an integrated evaluation of the identified potential risk mitigation initiatives. The outcome is the specification of a portfolio of mitigation initiatives that will be implemented over the WMP cycle.*
- *Provide a summary of the approved risk mitigation strategies for inclusion in the WMP submission. This summary must include schedules for implementation of the strategies, procedures for management oversight of implementation of the mitigations, and methods of evaluation of their effectiveness once deployed.*
- *Discuss the expected improvements in maturity and describe monitoring activities to assess the degree of improvement in maturity.*

Introduction to PG&E's Risk Evaluation Approach

Our risk management approach is based on conducting a quantitative risk assessment to determine Pacific Gas and Electric Company's (PG&E) overall utility risk from wildfire and PSPS for our service territory. Our approach is built on an iterative process that starts by identifying risks, evaluating how those risks impact our systems and the community, responding to risks through mitigation and control programs, and monitoring how well our risk mitigation and management programs are working. We discuss our approach in Section 6.1.1. Risk mitigation and management is an on-going effort through which we continuously evaluate risk and our response to that risk and adjust our programs to address them.

The intent of performing risk analysis is to understand the overall utility risk and the risk components related to wildfires and PSPS events across PG&E's service territory. We use this understanding of our risk to develop and prioritize the comprehensive wildfire mitigation strategy we discuss in this section and that achieves the goals and plan objectives described in Sections 4.1 and 4.2.

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; and (2) wildfire risk models that are built to help guide specific longer-term mitigations that improve the resiliency of our systems. To address the dynamic wildfire risk across our service territory we rely on two approaches. First, for Operational Mitigations like PSPS and Enhanced Powerline Safety Settings (EPSS), we employ operational models—these are models that produce outputs like the Fire Potential Index (FPI), a short-term look forward view to determine where in the service territory risk is elevated. These operational models help guide how we operate the grid. Second, for Resilience Mitigations—mitigations that are changing how we operate the grid—we use long-term planning models to help us develop and implement mitigations in areas of high risk and 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. We use our knowledge of key risk drivers and historic risk event data to develop and socialize distribution and transmission wildfire risk models. We use our risk models to develop risk buydown curves that allow us to optimize risk reduction for units worked and to develop a balanced portfolio of mitigation initiatives. Our balanced portfolio is designed to improve situational awareness, reduce risk by improving the resiliency of our systems, and address emerging threats through operational mitigations while we implement our longer-term mitigation initiatives.

Socializing risk model information with stakeholders helps them better understand how the risk models use data to develop risk-ranked circuit segments, structure-based, asset-based, or other ranked lists for mitigation activities. It also helps the risk teams identify where Subject Matter Expert (SME) input would better refine the risk rankings to address issues that may not be accounted for in the risk models but that impact decision-making. Socialization also drives improvements to the models through stakeholder feedback.

While we rely increasingly on our risk models to identify where the risks on our system are the greatest, there are still variations based on the maturity of the wildfire mitigation initiative and data quality. If a mitigation program ties to a specific element in our probability model, we rely on the output from the model to inform work prioritization. If a program does not tie to a specific probability model, or if we lack quality data, we prioritize our activities based on wildfire consequence.

Developing program risk buydown curves and risk-ranked prioritizations helps us evaluate investments across multiple programs. In addition to evaluating the outputs from the risk models and the risk buydown curves, we also consider other factors such as programs that address multiple risk drivers, local and geographic considerations, resource and other constraints, regulatory commitments, interactions among various programs, and time to implement the mitigation. Prioritization among programs still has room for improvement. We are working to improve this part of our process in conjunction with the California Public Utilities Commission (CPUC) and the other Investor-Owned Utilities (IOU) through the Risk-Based Decision-Making Framework Order Instituting Rulemaking (RBDF OIR).[89]

[89] Rulemaking (R.) 20-07-013.

7.1.2 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 mitigation initiatives. Table 7-1. Example of Stakeholder Roles and Responsibilities in the Decision-Making Process provides an example of the required information. 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 public safety partners);*
- *Identify the decision-making role of each stakeholder group (e.g., decision maker, consulted, informed); and*
- *Identify method of engagement (e.g., meeting, workshop, written comments).*

The electrical corporation must also describe how it communicates decisions to the identified key stakeholders.

PG&E's Wildfire Risk Governance Steering Committee (WRGSC) makes decisions about developing and prioritizing mitigation initiatives. Internal SMEs bring wildfire mitigation proposals to the WRGSC. The WRGSC reviews mitigation initiative proposals and considers the risk reduction from the proposed mitigation, 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 proposed mitigation plans approved by the WRGSC are an input into the annual (or General Rate Case (GRC) period) investment plan. Figure PG&E-7.1.2-1 is the WRGSC charter which sets forth who is on the Committee and outlines the decision-making process.

**FIGURE PG&E-7.1.2-1:
WILDFIRE RISK GOVERNANCE STEERING COMMITTEE CHARTER**

Wildfire Governance Steering Committee Charter

Purpose:

Drive decisions to prevent PG&E attributable ignitions and wildfires; and reduce impact of PSPS to customers of our communities.

Attendees:

Chair: EVP, Chief Risk Officer & Chief Safety Officer (Sumeet Singh)
Voting Members:
- SVP, Electric Operations (Janisse Quiñones)
- SVP, Electric Engineering (Joe Bentley)
- VP & Chief Audit Officer (Stephen Cairns)
- VP, Transmission and Distribution System Operations (Mark Quinlan)
- SVP, Vegetation Management & System Inspections (Peter Kenny)
- VP, Customer Care North Coast Region (Ronald Richardson)

Non-Voting Members:
- VP, Electric Engineering Asset and Regulatory (Martin Wyspianski)
- VP, Electric Ops, Projects & Construction (Ahmad Ababneh)
- Sr. Director, Wildfire Risk Management (Andy Abranches)
- VP, System Inspections (Jason Regan)
- VP, Electric Distribution Operations (Jeff Deal)
- VP, Undergrounding (Jamie Martin)
- VP, Regulatory Affairs (Meredith Allen)

Facilitators: Community Wildfire Safety Program 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 in person or virtually
- 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 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 weekly, Ad Hoc as requested
- Pre-read materials will be sent to meeting attendees ahead of the meeting
- Action items included in the meeting material
- 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, Community Wildfire Safety Program 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
- Approval of safety or quality improvement initiatives
- Resolutions to escalated action items flagged for committee approval
- Self-report corrective action plans

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 Daily, Weekly and/or Monthly Operating Reviews.*

Internal stakeholders who interact with the WRGSC as it evaluates and selects wildfire mitigation initiatives include: Wildfire Risk Management; Asset Strategy; Engineering and Standards; Ignitions Investigations; Vegetation Management (VM); Investment Planning; Major Projects; Electric Operations; and Asset Knowledge and Management.

PG&E also collaborates with external stakeholders such as the California Department of Forestry and Fire Protection, Energy Safety, the CPUC, environmental agencies such as California Fish and Game and Regional Water Quality Boards, California Independent System Operator, other California IOUs, California Fire Safe Councils, PG&E customers, Community Based Organizations, local communities, and government leaders.

In addition, PG&E interacts with our customers through meetings and town-hall type events hosted by our Regional Vice Presidents (VP). The Regional VPs are voting members of the WRGSC and can bring customer concerns and input back to the committee. While we value and carefully consider input from our customers, PG&E is ultimately responsible for ensuring safety of our system and communities and may not act on every suggestion we receive. In Section 8.5, we discuss how we interact with our customers and how their input 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 those proposals that the WRGSC does not approve initially, the governance committee provides the team targeted guidance and teams may make additional proposals in the future.

Table 7-1 below lists key stakeholders and their role in the wildfire risk mitigation evaluation process.

TABLE 7-1:
STAKEHOLDER ROLES AND RESPONSIBILITIES IN DECISION MAKING PROCESS

Stakeholder	Stakeholder Point of Contact	Electrical Corporation Point of Contact	Stakeholder Role	Engagement Methods
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 Access and Functional Needs (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
Public	Fire Agency representatives	Public Safety Specialist (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.

TABLE 7-1:
STAKEHOLDER ROLES AND RESPONSIBILITIES IN DECISION MAKING PROCESS
(CONTINUED)

Stakeholder	Stakeholder Point of Contact	Electrical Corporation Point of Contact	Stakeholder Role	Engagement Methods
Electrical Corporation SMEs	Public Safety Specialists	Senior Director Wildfire Risk	Provide insight into local environmental conditions to support wildfire mitigation planning.	WRGSC
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
Electrical corporation leadership	Vice President, Chief Audit Officer, and Interim Chief Risk Officer	Senior Director Wildfire Risk	• WRGSC-Chair • Drives decisions to prevent PG&E attributable ignitions and wildfires and reduce impact of PSPS to customers of our communities. • Reviews and approves: – 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; – Approval of safety or quality improvement initiatives; – Resolutions to escalated action items flagged for committee approval; and – Self-report corrective action plans.	WRGSC Meetings

TABLE 7-1:
STAKEHOLDER ROLES AND RESPONSIBILITIES IN DECISION MAKING PROCESS
(CONTINUED)

Stakeholder	Stakeholder Point of Contact	Electrical Corporation Point of Contact	Stakeholder Role	Engagement Methods
Electrical corporation leadership	Senior Vice President (SVP), Electric Operations	Senior Director Wildfire Risk	• WRGSC-Voting Member • Drive decisions to prevent PG&E attributable ignitions and wildfires; and reduce impact of PSPS to customers of our communities. • Provides feedback on constraints, operability, and ability to execute on potential mitigation plans.	WRGSC Meetings
Electrical corporation leadership	SVP, Electric Engineering	Senior Director Wildfire Risk	• WRGSC-Voting Member • Drives decisions to prevent PG&E attributable ignitions and wildfires; and reduces impact of PSPS to customers of our communities. • Provides feedback on the engineering and strategic objectives of potential mitigation plans, including the impacts to the investment planning portfolio.	WRGSC Meetings
Electrical corporation leadership	VP & Chief Audit Officer	Senior Director Wildfire Risk	• WRGSC-Voting Member • Drives decisions to prevent PG&E attributable ignitions and wildfires; and reduces impact of PSPS to customers of our communities. • Provides feedback on the auditability of the mitigation plans and provides an independent lens on decision making.	WRGSC Meetings

TABLE 7-1:
STAKEHOLDER ROLES AND RESPONSIBILITIES IN DECISION MAKING PROCESS
(CONTINUED)

Stakeholder	Stakeholder Point of Contact	Electrical Corporation Point of Contact	Stakeholder Role	Engagement Methods
Electrical corporation leadership	VP, Transmission and Distribution System Operations	Senior Director Wildfire Risk	• WRGSC-Voting Member: • Drives decisions to prevent PG&E attributable ignitions and wildfires; and reduces impact of PSPS to customers of our communities. • Provides feedback on impacts to system operations based on planned work.	WRGSC Meetings
Electrical corporation leadership	SVP, VM & System Inspections	Senior Director Wildfire Risk	• WRGSC-Voting Member: • Drives decisions to prevent PG&E attributable ignitions and wildfires; and reduces impact of PSPS to customers of our communities. • Provides feedback on impacts relating to VM and inspection.	WRGSC Meetings
Electrical corporation leadership	VP, Customer Care North Coast Region	Senior Director Wildfire Risk	• WRGSC-Voting Member • Drives decisions to prevent PG&E attributable ignitions and wildfires; and reduces impact of PSPS to customers of our communities. • Provides feedback from customer lens.	WRGSC Meetings
Electrical corporation leadership	VP, Electric Engineering Asset and Regulatory	Senior Director Wildfire Risk	• WRGSC-Non-Voting Member • Drives decisions to prevent PG&E attributable ignitions and wildfires; and reduces impact of PSPS to customers of our communities. • Provides feedback on asset mitigation strategies.	WRGSC Meetings

TABLE 7-1:
STAKEHOLDER ROLES AND RESPONSIBILITIES IN DECISION MAKING PROCESS
(CONTINUED)

Stakeholder	Stakeholder Point of Contact	Electrical Corporation Point of Contact	Stakeholder Role	Engagement Methods
Electrical corporation leadership	VP, Electric Ops, Projects & Construction	Senior Director Wildfire Risk	• WRGSC-Non-Voting Member • Drives decisions to prevent PG&E attributable ignitions and wildfires; and reduces impact of PSPS to customers of our communities. • Provides feedback on executability of wildfire programs.	WRGSC Meetings
Electrical corporation leadership	Senior Director, Wildfire Risk Management	WRGSC	• WRGSC-Non-Voting Member • Drives decisions to prevent PG&E attributable ignitions and wildfires; and reduces impact of PSPS to customers of our communities.	WRGSC Meetings
Electrical corporation leadership	VP, System Inspections	Senior Director Wildfire Risk	• WRGSC-Non-Voting Member • Drives decisions to prevent PG&E attributable ignitions and wildfires; and reduces impact of PSPS to customers of our communities. • Provides feedback on inspections.	WRGSC Meetings
Electrical corporation leadership	VP, Electric Distribution Operations	Senior Director Wildfire Risk	• Drives decisions to prevent PG&E attributable ignitions and wildfires; and reduces impact of PSPS to customers of our communities. • Provides feedback on execution on distribution system.	WRGSC Meetings

TABLE 7-1:
STAKEHOLDER ROLES AND RESPONSIBILITIES IN DECISION MAKING PROCESS
(CONTINUED)

Stakeholder	Stakeholder Point of Contact	Electrical Corporation Point of Contact	Stakeholder Role	Engagement Methods
Electrical corporation leadership	VP, Undergrounding	Senior Director Wildfire Risk	• WRGSC-Non-Voting Member • Drives decisions to prevent PG&E attributable ignitions and wildfires; and reduces impact of PSPS to customers of our communities. • Provides feedback on underground mitigation strategy.	WRGSC Meetings
Electrical corporation leadership	VP, Regulatory Affairs	Senior Director Wildfire Risk	• WRGSC-Non-Voting Member • Drives decisions to prevent PG&E attributable ignitions and wildfires; and reduce impact of PSPS to customers of our communities. • Provides feedback based on regulatory needs.	WRGSC Meetings

Note: External stakeholder roles and responsibilities are not included in Table 7-1 above because the external stakeholders, the points of contact, roles, and engagement methods vary. We provide a list of external stakeholders in the narrative above.

7.1.3 Risk-Informed Prioritization

In making decisions on 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 areas of its service territory at risk from wildfire for potential mitigation initiatives, 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., areas in top 20 percent for risk, areas in top 20 percent for consequences);*
  - Feasibility *constraints (e.g., limitations on data resolution, jurisdictional considerations, accessibility); and*
  - Present *a list that identifies, describes, and prioritizes areas of its service territory at risk from wildfire for potential mitigation initiatives based solely on overall utility risk, including the associated risk drivers.*

PG&E considers wildfire risk to our service territory based on geographic, statistical, and feasibility factors and uses this information to prioritize our mitigation initiatives. 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 High Fire Threat District (HFTD) and High Fire Risk Area (HFRA)[90] 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.

We narrow the geographic scale to focus on where assets and structures are located within HFTD and HFRA areas. For assets and structures, we determine the risk at a specific location at the pixel level. A pixel is defined as an area that measures 100 x 100 m.

All pixels are aggregated to either the circuit segment level or the structure level and include both overhead lines and assets. 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, as well as operational, planning, and work executability, in these select locations.

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90 PG&E defines its HFRA in Section 6.4.

Programs such as undergrounding and system hardening are risk prioritized at the circuit segment level. For component-based programs such as non-exempt fuse replacement we prioritize risk at the asset level.

For VM work we also determine consequences at a specific location at the pixel level. The VM program is also developing specific geographic-based responses to address high risk areas. In 2023, we are developing Areas of Concern (AOC) to better focus VM efforts to address high risk locations such as those experiencing higher volumes of PSPS events and/or ignitions. Within the AOC we consider location-specific vegetation risk and develop specific activities to address the local risks.

Statistical Approach

PG&E determines wildfire risk to areas of our service territory by developing prioritized risk buydown curves using our various risk models. The risk buydown curve identifies locations where investing in mitigations will reduce the most amount of the 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 while subsequent tranches will reduce less risk.

In areas of our system where we are confident that the data in our risk models accurately reflects the local conditions, we prioritize our mitigations considering both the probability of an event and the consequence of that event.

In areas of our system where we are less confident that the data in our risk models accurately reflects the local conditions, we assume that the probability of an event is equal across the system, and we prioritize our mitigations by only the potential consequence of the risk event. An example of this would be how distribution inspection cadence is defined in the HFTD and HFRA. As local conditions can change regardless of the modeled asset probability of failure, the inspection cadence is defined by wildfire consequence to ensure PG&E has the appropriate level of eyes-on-risk in the right places.

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 how our planned mitigation work will impact the local community.

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.[91] Since our goal is to remove as much risk from the system through undergrounding as quickly as possible, in certain circumstances we may choose to postpone undergrounding a circuit segment because of feasibility constraints and instead choose to move forward with

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91 PG&E discusses our Wildfire Feasibility Efficiency in more detail in Area for Continued Improvement (ACI) PG&E-22-34.

other segments that can be completed more quickly. In these cases, we continue to monitor the risk profile of the constrained segment and ensure that additional programs such as EPSS are in place to mitigate the risk.

Our VM activities can be, and often are, constrained by environmental delays, customer concerns, permitting delays/restrictions, operational holds, weather conditions, active wildfire, and accessibility into the area. Because of these constraints, when we develop the VM workplan we often provide a larger volume of risk-prioritized work to the execution team to ensure 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 and/or other monitoring programs.

Prioritized Risk Areas in PG&E's Service Territory

PG&E prioritizes all areas of HFTD and HFRA when considering mitigation activities. For consistency in reporting, PG&E determined that 41 circuit segments contribute to the top 5 percent of cumulative risk.[92] Table 7-2 below lists the top 41 risk circuit segments, the overall utility risk, and the contribution by key risk driver.

92 Based on the criteria set forth in the WMP Guidelines, Section 6.4.2.

TABLE 7-2:
PRIORITIZED AREAS IN PG&E'S SERVICE TERRITORY BASED ON OVERALL UTILTY RISK

Line No.	Circuit Segment Name	Wildfire Mean Risk Score	HFTD Miles	Overall Risk Score	Percent Veg. Risk	Percent Equip. Risk	Percent Contact From Object Risk	Percent PSPS Risk
1	INDIAN FLAT 1104CB	0.0393	13.80	118.47	25%	56%	18%	0%
2	BONNIE NOOK 1101CB	0.0295	17.80	91.28	46%	37%	11%	6%
3	ALLEGHANY 1102CB	0.0240	18.91	88.61	34%	55%	8%	3%
4	OAKHURST 110310140	0.0288	18.76	88.41	42%	46%	11%	1%
5	SILVERADO 2104515946	0.0254	19.06	85.60	45%	40%	9%	6%
6	HIGHLANDS 1102628	0.0261	15.78	75.58	18%	58%	24%	0%
7	UPPER LAKE 11011276	0.0250	12.29	67.22	39%	50%	11%	0%
8	MIDDLETOWN 110148212	0.0352	9.83	58.82	51%	37%	11%	1%
9	APPLE HILL 21026552	0.0258	13.02	57.11	43%	40%	15%	2%
10	NOTRE DAME 11042028	0.0245	11.39	50.10	55%	33%	11%	1%
11	CLAYTON 221296224	0.0341	10.18	47.28	33%	51%	16%	1%
12	ANTLER 11011384	0.0387	10.34	46.88	48%	37%	14%	1%
13	MONTICELLO 1101654	0.0268	8.30	43.06	30%	47%	21%	2%
14	BALCH NO 1 1101105414	0.0313	7.47	42.19	18%	54%	28%	0%
15	CURTIS 170356972	0.0250	8.42	41.10	17%	50%	33%	0%
16	MONTICELLO 1101630	0.0396	4.94	41.08	31%	47%	20%	2%
17	PINE GROVE 1101CB	0.0473	5.05	32.00	34%	45%	17%	3%
18	BUCKS CREEK 1101CB	0.0292	4.81	28.51	21%	69%	10%	0%
19	SILVERADO 2104646776	0.0343	5.69	26.59	49%	30%	7%	14%
20	CALISTOGA 1102131531	0.0272	5.04	26.03	62%	30%	6%	3%
21	APPLE HILL 1104CB	0.0260	5.65	16.86	35%	44%	14%	6%
22	MIDDLETOWN 1101171414	0.0245	3.59	16.55	43%	49%	8%	0%
23	ELECTRA 1102CB	0.0264	2.60	13.93	13%	66%	22%	0%
24	ORO FINO 1102CB	0.0317	2.73	12.60	43%	45%	10%	2%
25	FRENCH GULCH 1101CB	0.0250	2.71	12.22	13%	63%	21%	3%
26	PARADISE 1103283794	0.0278	2.55	12.12	31%	47%	19%	3%
27	PARADISE 11061212	0.0270	2.37	12.04	28%	35%	12%	26%
28	CRESTA 1101103126	0.0240	0.87	4.95	35%	55%	9%	1%
29	CRESTA 1101546650	0.0259	0.90	4.36	23%	67%	9%	0%
30	MONTICELLO 1101CB	0.0305	0.54	3.06	21%	60%	19%	0%
31	TIGER CREEK 0201CB	0.0409	0.40	2.30	39%	53%	8%	0%
32	INDIAN FLAT 11044440	0.0386	0.24	1.74	21%	61%	18%	0%
33	CALPINE 1144304	0.0684	0.05	1.71	14%	77%	9%	1%
34	APPLE HILL 2102CB	0.0901	0.17	1.43	32%	46%	18%	4%

TABLE 7-2:
PRIORITIZED AREAS IN PG&E'S SERVICE TERRITORY BASED ON OVERALL UTILITY RISK
(CONTINUED)

Line No.	Circuit Segment Name	Wildfire Mean Risk Score	HFTD Miles	Overall Risk Score	Percent Veg. Risk	Percent Equip. Risk	Percent Contact From Object Risk	Percent PSPS Risk
35	MIDDLETOWN 1103CB	0.0270	0.05	1.09	15%	66%	18%	0%
36	PLACERVILLE 210658118	0.1047	0.11	0.90	16%	60%	23%	1%
37	BALCH NO 1 1101CB	0.0533	0.01	0.82	33%	48%	19%	0%
38	ALLEGHANY 11021101/2	0.0661	0.01	0.34	29%	61%	9%	0%
39	CALPINE 1144962	0.0244	0.04	0.21	7%	81%	11%	0%
40	CAMP EVERS 2105BL 2101	0.0449	0.00	0.09	82%	16%	2%	0%
41	MARIPOSA 2101929360	0.0334	0.07	0.09	4%	82%	14%	0%

7.1.4 Mitigation Selection Process

7.1.4.1 Identifying and Evaluating Mitigation Initiatives

The electrical corporation must describe how it identifies and evaluates options for mitigating wildfire and PSPS risk at various analytical scales. The current guidelines governing this process are derived from the RBDF established in the Safety Model and Assessment Proceeding (S-MAP). The S-MAP is currently being updated in CPUC proceeding R.20-07-013. In due course, the electrical corporation's risk mitigation identification procedure must align with results from this proceeding. The electrical corporation must describe the following:

- *The procedures for identifying and evaluating mitigation initiatives (comparable to 2018 S-MAP Settlement Agreement, row 26), including the use of risk buy-down estimates (e.g., risk-spend efficiency) and evaluating the benefits and drawbacks of mitigations;*
- *To the extent possible, multiple potential locally relevant mitigation initiatives to address local wildfire risk drivers (see 2018 S-MAP Settlement Agreement, row 29);*
- *The approach the electrical corporation uses to characterize uncertainties and how the electrical corporation's evaluation and decision-making process incorporates these uncertainties (see 2018 S-MAP Settlement Agreement, rows 29 and 30);*
- *Two or more potential mitigation initiatives for each risk driver included in the list of prioritized areas (Table 7-2 in Section 7.1.3), including the following information:*
  - *The initiatives and activities;*
  - *Expected risk reduction and impact on individual risk components;*
  - *Estimated implementation costs;*
  - *Relevant uncertainties;*
  - *Implementation schedule; and*
  - *How the electrical corporation uses Multi-Attribute Value Functions (MAVF) and/or other specific risk factors (as identified in 2018 S-MAP or subsequent relevant CPUC Decisions) in evaluating different mitigation.*

PG&E is an active participant in the Commission's RBDF OIR which was initiated to build upon the requirements for the utility risk assessment and mitigation framework adopted in the S-MAP.[93] As of December 2022, the Commission had issued three Final Decisions which:

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[93] R.20-07-013.

- Adopted safety and operational metrics, modified transparency guidelines, approved minor technical clarifications to the RBDF adopted in D.18-12-014 and adopted a revised S-MAP lexicon.[94]

- Defined certain reporting requirements for the Risk Spending Accountability Reports, updated certain RAMP requirements, and eliminated certain gas safety reporting requirements.[95]

- Replaced the MAVF with a cost-benefit approach that includes standardized dollar valuations for consequences from risk events; required the IOUs to implement the modified RDF to assess and rank risks and mitigations in their RAMP and GRC filings starting with PG&E's 2024 RAMP, and directed the IOUs to undertake environmental and social justice pilots in the next RAMP filing.[96]

PG&E will comply with the requirements from the final decisions in this proceeding. However, given the timing of this rulemaking, the risk analysis and mitigation selection described in this WMP are more closely aligned to the requirements set forth in the S-MAP Settlement Agreement. Below we describe the different requirements from the S-MAP Settlement Agreement related to identifying and evaluating mitigations and how PG&E incorporates each of these requirements into our processes. This discussion only focuses on pertinent rows from the S-MAP Decision.

S-MAP Requirement: Rows 15-25 of the S-MAP Settlement Agreement describe the process that utilities will follow for developing the risk bow-tie (Row 15), calculating pre-mitigation and post-mitigation scores, and measuring risk reduction provided by a mitigation (Rows 16-24), and calculating Risk Spend Efficiency (RSE) scores (Row 25).

PG&E's Action(s) to Comply with the S-MAP Requirement: PG&E complied with the S-MAP Settlement Agreement requirements in our 2020 RAMP Report.[97] The Commission reviewed our RAMP Report and found that PG&E complied with the procedures adopted in the S-MAP Settlement Agreement.[98] In the following section we describe in more detail how we complied with Rows 15-25 of the S-MAP to develop mitigation initiatives in the 2023 GRC (where relevant) and in this WMP submission.

S-MAP Requirement: Row 15 of the S-MAP Settlement Agreement requires the utility to include a bow-tie illustration for each RAMP risk and to identify which element(s) of the associated bow tie a mitigation will address.

PG&E's Action(s) to Comply with the S-MAP Requirement: In Section 7.1.4.2 below we describe—and provide tables showing—how we develop and map mitigation initiatives to address the individual risk drivers (left side of the bow-tie) and risk consequences

94 D.21-11-009, Decision Addressing Phase I, Track 1 and 2 Issues.

95 D.22-10-002, Decision Addressing Phase I, Tracks 3 and 4 Issues.

96 D.22-12-027, Phase II Decision Adopting Modifications to the Risk-Based Decision-Making Framework Adopted in D.18-12-014 and Directing Environmental and Social Justice Pilots.

97 Application (A.) 20-06-012, Chapter 3, Risk Modeling and RSE.

98 D.22-03-008, Conclusions of Law 4.

(right side of the bow-tie) for our distribution and transmission wildfire risks and to reduce the effects of PSPS on our customers. We included transmission and distribution wildfire risk bow-tie illustrations in the 2022 WMP.[99]

S-MAP Requirement: Rows 16-24 of the S-MAP Settlement Agreement describe the methods for calculating pre-mitigation and post-mitigation risk scores and for measuring risk reduction provided by a mitigation at the tranche level using the MAVF.

PG&E's Action(s) to Comply with the S-MAP Requirement: In the 2020 RAMP Report, and again in the 2023 GRC, PG&E provided the pre- and post-mitigation risk scores for the distribution wildfire risk. In the 2023 GRC, we reported that the pre-mitigation risk distribution wildfire score was 23,220 and the post-mitigation risk score was 5,449.[100]

The suite of mitigations discussed in the WMP are similar to the mitigations forecast in the GRC. The risk modeling workpapers provided in the GRC[101] include the tranche-level pre and post-mitigation risk scores for the distribution wildfire risk (GRC and WMP).

S-MAP Requirement: Row 26 of the S-MAP Settlement Agreement requires that the utility provide a ranking of all RAMP mitigations in its GRC. In the RAMP and the GRC the utility will clearly and transparently explain its rationale for selecting mitigations for each risk and for its selection of its overall portfolio of mitigations. The utility is not bound to select its mitigation strategy based solely on RSE ranking. Mitigation selection can be influenced by other factors and the utility will explain whether and how any such factors affected the utility's mitigation selections.

PG&E's Action(s) to Comply with the S-MAP Requirement: In the 2023 GRC, PG&E provided a table that included RSE scores for each distribution wildfire mitigation, including PSPS impact reduction initiatives.[102] In GRC testimony, we provide narratives describing each forecast mitigation and our rationale for including it in our mitigation portfolio.[103]

In Section 8 of this WMP, we provide detailed information about all our distribution and transmission wildfire mitigation initiatives and the risks that they reduce. In Section 9 of this WMP we provide detailed information about our PSPS program and how we use PSPS to mitigate the consequences of wildfire risk.

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99 PG&E's 2022 Wildfire Mitigation Plan, OEIS Docket #2022-WMP – Final Revision Notice Responses (July 26, 2022) p. 78, Figure 4.2-1 and p. 79, Figure 4.2-2 and Figure 4.2-3.

100 A.21-06-021, Exhibit (PG&E-4), p. 3-23, lines 1-14.

101 A.21-06-021, Exhibit (PG&E-15), Chapter 1, Risk Modeling Workpapers Cover Sheet, Workpapers 1-7, referencing a Zip File on PG&E's website containing the public workpapers.

102 A.21-06-021, Exhibit (PG&E-4), pp. 3-39 to 3-30, Table 3-4.

103 A.21-06-021, Exhibit (PG&E-4), Chapters 4.0-4.6, Wildfire Risk Mitigations.

S-MAP Requirement: Row 29 of the S-MAP Settlement Agreement requires that inputs and computations associated with the MAVF risk modeling must be clearly specified, mathematically correct and logically sound.

PG&E's Action(s) to Comply with the S-MAP Requirement: In the 2023 GRC, PG&E provided risk modeling workpapers that include the inputs and computations for our distribution wildfire MAVF.

S-MAP Requirement: Row 30 of the S-MAP Settlement Agreement requires the utility to identify critical parameters and assumptions made in performing its risk analysis and explain why such parameters are critical. The utility will be prepared to complete a sensitivity analysis of its results when requested.

PG&E's Action(s) to Comply with the S-MAP Requirement: PG&E's risk modeling workpapers include the parameters and assumptions relied upon in performing risk analysis. In the 2023 GRC, PG&E performed sensitivity analyses as requested. For example, PG&E re-calculated RSEs by changing the weight of different attributes in the MAVF and changing the scaling function from a non-linear to a linear function.

In Section 7.1.4.2 below, PG&E describes how we evaluate and select mitigation initiatives for each risk based on the risk prioritization described in Section 7.1.3 above.

While the requirements of S-MAP defined by CPUC are applicable only to Distribution, we follow a similar risk assessment and mitigation identification and evaluation process for our Transmission system.

7.1.4.2 Mitigation Initiative Prioritization

After identifying and characterizing the mitigation options, the electrical corporation must analyze the options to determine which will reduce risk the most, given limitations and constraints (e.g., resources available for mitigation initiatives). To the greatest extent practicable, the electrical corporation must make these determinations using its existing framework of project prioritization. The electrical corporation must strive to optimize its resources for maximum risk reduction.

The electrical corporation should seek the best integrated portfolio of mitigation initiatives to meet performance objectives. Objectives may be based on quantified risk assessment results (see Section 6) or other values prioritized by the electrical corporation or broader stakeholder groups (e.g., environmental protection, public perception, resilience, cost). At a minimum, the electrical corporation must do the following:

- *Evaluate its potential mitigation initiatives. This evaluation will yield a prioritized list of initiatives. The objective is for the electrical corporation to identify the preferable initiatives for specific geographical areas. (Comparable to 2018 S-MAP Settlement Agreement, rows 12, 26, and 29.)*
- *Identify the best mitigation initiatives for all geographical areas create a portfolio of projects expected to provide maximal benefits within known limitations and constraints. (Comparable to 2018 S-MAP Settlement Agreement, rows 12, 26, and 29.)*
- *Explain how the electrical corporation is optimizing its resources to maximize risk reduction. Describe how the proposed initiatives 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.*

This process is expected to be iterative due to the competing nature of performance objectives and their complex interrelationships.

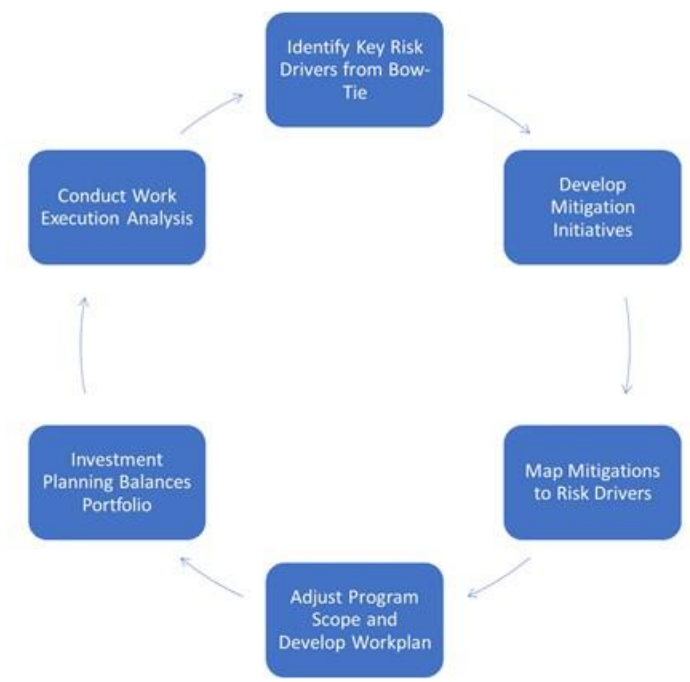
The electrical corporation must describe how it prioritizes mitigation initiatives to reduce both wildfire and PSPS risk. This discussion must include the following:

- *A high-level schematic showing the procedures and evaluation criteria used to evaluate potential mitigation initiatives. At a minimum, the schematic must demonstrate the roles of quantitative risk assessment, resource allocation, evaluation of other performance 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 detail must be sufficiently specific to understand 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).*

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

Figure PG&E-7.1.4-1A below is a schematic describing 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. We describe this process in the section below.

FIGURE PG&E-7.1.4-1A:
DEVELOPING THE BALANCED MITIGATION PORTFOLIO



Aligning to the Commission's Risk-Based Decision-Making Framework

PG&E's mitigation selection and evalulation process is aligned to the Commission's RBDF for energy utilities to consider how qualitiative safey, reliability, and security issues can be connected to the quantitative decisions in a GRC, in which the utilities request funding for such activities.[104] The S-MAP is the initial phase of the Risk Based Decision Making Framework that is intended to: "(1) allow parties to understand the models the utilities propose to use to prioritize … projects … to mitigate risks; and (2) allow the Commission to establish standards and requirements for those

[104] D.14-12-025, pp. 54-55, Ordering Paragraph 1.

models."[105] The SMAP Settlement Agreement[106] establishes the "minimum required steps for large Utilities to take to analyze risk and mitigations for the RAMP and GRC."[107] We described how we comply with the S-MAP Settlement Agreement in Section 7.1.4.1 above.

To develop our proposed list of mitigations, PG&E starts with the bow-tie illustration required by Step 15 of the S-MAP Settlement Agreement. The bow-ties for system-wide and distribution wildfire risk were included in PG&E's 2023 GRC[108] and the bow-ties for system-wide, distribution and transmission wildfire risk were included in PG&E's 2022 WMP.[109] The distribution wildfire bow-tie was also included in the 2020 RAMP (p. 10-8, Figure 10-2). While PG&E did not produce a PSPS bow-tie for the 2023 GRC or 2022 WMP, PG&E models PSPS and considers programs to mitigate the consequences of PSPS as part of its mitigation analysis.

Wildfire risk was, and remains, PG&E's top risk. Since the GRC is a CPUC jurisdictional proceeding, only distribution mitigations are considered in the RAMP. For the WMP, PG&E addresses both our distribution and tranmission risks. Therefore, when evaluating mitigation initiatives for the WMP, PG&E includes both distribution and transmission wildfire risk.

At the time PG&E filed our 2020 RAMP Report, PSPS was considered a wildfire mitigation. Just before we filed our 2023 GRC, the Commission ordered PG&E to provide testimony in the GRC concerning updated risk analysis of the estimated consequences of initiating PSPS events and that the testimony must contain analysis and discussion of the consequences of PSPS for customers and how PG&E analyzes those consequences.[110] PG&E complied with the Commission's ruling in our opening GRC testimony.[111]

The 2023 WMP time period, 2023-2025, generally overlaps with PG&E's 2023 GRC. The GRC will fund work from 2023 through 2026. Our evaluation and selection of a mitigation portfolio considers both the longer-term GRC/WMP periods as well as an annual re-evaluation that looks at work completed to date, evolving risk analysis, changing risk conditions, the introduction of new technology, and new information about the effectiveness of new or existing programs.

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105 D.18-12-014, p. 5.

106 The S-MAP Settlement Agreement was adopted with modifications in D.18-12-014 as part of the S-MAP proceeding.

107 D.18-12-014, p. 10.

108 A.21-06-021, Exhibit (PG&E-4), p. 3-24, Figure 3-2 and Figure 3-3.

109 PG&E's 2022 WMP, OEIS Docket #2022-WMP – Final Revision Notice Responses (July 26, 2022) p. 78, Figure 4.2-1 and p. 79, Figure 4.2-2 and Figure 4.2-3.

110 A.21-06-021, *ALJ Lirag E-Mail Ruling Denying Joint Motion by Cal Advocates and FEITA* (June 3, 2021).

111 A.21-06-021, Exhibit (PG&E-4), p. 3-33, line 12 to p.3-37, line 9.

Developing Mitigation Initiatives

PG&E focuses on three key elements in developing our wildfire mitigation portfolio:

1) Identifying and selecting mitigation intiatives based on the greatest amount of risk reduction;

2) Considering geographic specific limitations and other constraints to develop a balanced portfolio of mitigations; and

3) Optimizing resources to maxmize risk reduction across the system.

We begin developing our list of proposed mitigations by analyzing risk events, risk drivers, and consequences. We first analyze the risk drivers on the left side of the risk bow-tie and the risk consequences on the right side of the bow-tie and then identify existing programs or develop new programs to eliminate or minimize each risk, by driver, and each of the potential consequences.

PG&E's wildfire mitigations are divided into three categories: Comprehensive Monitoring and Data Collection; Operational Mitigations; and System Resilience. These categories are broadly defined below:

- Comprehensive Monitoring and Data Collection: Programs designed to provide insight into the changing environmental hazards around our assets and the condition of our equipment. Comprehensive Monitoring and Data Collection programs provide continuous monitoring capability. We use information from our comprehensive monitoring data collection programs to decide what mitigations to deploy, and where and when to deploy them. For example, PG&E's weather stations are relied on to monitor wind speeds, wind gusts and relative humidity. Readings from stations are evaluated in real-time to support decision-making regarding whether to implement PSPS.

- Operational Mitigations: Programs that provide on-going risk reduction and influence how we manage the environment around the electric grid. Operational Mitigations are generally short cycle initiatives that can be deployed quickly. Operational mitigations include initiatives we undertake to support customers before, during, and after wildfire events. For example, we perform maintenance and repair activities on our equipment to ensure that the equipment is properly installed and maintained to prevent operational failures and reduce system risk, including ignition risk. EPSS and PSPS are also examples of operational mitigations.

- System Resilience: Mitigations designed to reduce ignition risk by changing how PG&E's grid is constructed and operated. For example, when we identify deterioration in our distribution poles, they are remediated through replacement or reinforcement, which reduces the risk of ignition. Moving overhead lines underground is another example of system resilience.

Table PG&E-7.1.4-1 below shows the wildfire risk drivers and examples of the key programs PG&E identified to address them. Table PG&E-7.1.4-2 shows the wildfire consequences and the programs we use to address them. The tables are not exhaustive. A complete list of mitigations PG&E is implementing during the period covered by this WMP is provided in Section 7.2.1 below.

TABLE PG&E-7.1.4-1:
MAPPING MITIGATION INITIATIVES TO WILDFIRE RISK DRIVER – MITIGATIONS DESIGNED TO REDUCE FREQUENCY OF RISK EVENTS

	Mitigation Initiatives[(a)]								
	Operational Mitigations						Resilience Mitigations		
Risk Driver	1	2	3	4	5	6	7	8	9
Vegetation Contact	X	X	X		X	X	X	X	X
Equipment/Facility Failure	X	X	X	X	X	X	X	X	X
Contact from Object	X	X	X		X	X	X	X	X
Wire to Wire Contact	X	X				X	X	X	X
Unknown	X	X	X		X	X	X	X	X
Other		X	X		X	X	X		
Utility/Work Operation		X	X	X	X				
Vandalism/Theft		X	X		X	X	X		
Contamination	X	X	X		X	X	X		
CC – Seismic Scenario			X		X	X	X		

Note: Comprehensive Monitoring and Data Collection mitigations are not included in Table PG&E-7.1.4-1 because they are foundational mitigations.

(a) Key Mitigation Programs:

Operational Mitigations

1. PSPS;
2. EPSS;
3. VM Programs;
4. Partial Voltage Detection;
5. QEW On Site Standard; and
6. Downed Conductor Detection (DCD) Devices;

Resilience Mitigations:

7. Undergrounding;
8. Overhead Hardening; and
9. Breakaway Connectors.

TABLE PG&E-7.1.4-2:
MAPPING MITIGATION INITIATIVES TO WILDFIRE OUTCOMES – MITIGATIONS DESIGNED TO REDUCE RISK EVENT CONSEQUENCES

Mitigation Initiatives			
Outcome	**Pole Clearing**	**Substation Defensible Space**	**Safety Infrastructure Protection Team**
RFW Catastrophic Fires	X	X	X
RFW Destructive Fires	X	X	X
Non-RFW Catastrophic Fires	X	X	X
Non-RFW Destructive Fires	X	X	X
Non-RFW Small Fires	X	X	X
Non-RFW Large Fires	X	X	X
Seismic-RFW Catastrophic Fires	X	X	X
RFW Large Fires	X	X	X
RFW Small Fires	X	X	X
Seismic Non-RFW Catastrophic Fires	X	X	X

In addition to developing mitigations that map to individual risk drivers, PG&E also considers the impact mitigation initiatives will have at the cross-driver level. Because cross-driver initiatives mitigate multiple risk drivers, the effectiveness of the program is generally higher. As such, we consider tradeoffs between driver specific mitigations like VM against cross-driver mitigations like EPSS.

Table PG&E-7.1.4-3 below is an example of the relationships among risk drivers, initiatives that mitigate one risk driver, and initiatives that mitigate multiple risk drivers.

TABLE PG&E-7.1.4-3:
MAPPING RISK DRIVERS, INITIATIVES AND CROSS DRIVERS

<table>
<tr><th>Driver</th><th>Initiative</th><th>Cross-Driver Initiative & Situational Awareness</th></tr>
<tr><td>Vegetation</td><td>Routine VM, VM for Operational Mitigations, Focused Tree Inspections (AOC)</td><td rowspan="2">Situational Awareness: EPSS, PSPS, DCD, Hazard Awareness and Warning Center (HAWC)

Grid Hardening: System Hardening Overhead, System Hardening Underground, Remote Grids</td></tr>
<tr><td>Equipment Failure</td><td>Inspections, Maintenance, Surge Arrester, Expulsion Fuse Replacements</td></tr>
</table>

Balancing the Mitigation Portfolio

Risk identification and assessment is a continuous process. We evaluate and re-evaluate our risks and the most effective ways to address them. Given the dynamic environment, we regularly monitor the effectiveness of our existing programs. On an annual basis we add new programs, revise the scope of existing programs, and eliminate programs that are no longer as effective. Operational mitigations are adjusted on a more frequent basis.

Optimizing the portfolio consists of analyzing and balancing multiple factors such as risk reduction values, geographic considerations, feasibility constraints, available resources, regulatory requirements, and other commitments. This analysis is consistent with the requirements listed in Row 26 of the S-MAP Settlement Agreement requiring that we: clearly explain our rationale for selecting mitigations for each risk; explain how we selected our overall portfolio of mitigations; and that we are not bound to select our mitigation strategy based solely on RSE ranking but can consider other factors.

The type of mitigation tradeoff and effectiveness analysis we conduct informed PG&E's decision to transition away from the Enhanced Vegetation Management (EVM) program. While EVM was successful in mitigating vegetation risk in the HFTD, we determined that EPSS, along with routine VM, was more effective at reducing risk and was less resource intensive.

In balancing our mitigation portfolio, we also take into consideration local geography such as water crossings, gradient, and the types and density of local vegetation. PG&E considers other unique local factors such as fire history, ingress/egress, and community risk factors. We provide local geographic information about our undergrounding projects in ACI PG&E-22-16. ACI PG&E-22-16 includes project coordinates (latitude and longitude) for our planned undergrounding work. PG&E also makes local information about undergrounding projects widely available to our communities. The PG&E.com website[112] includes county-by-county maps that show the areas where we are prioritizing undergrounding in 2022 and 2023 to have the greatest impact on reducing wildfire risk.

As we evaluate where to deploy mitigations, we consider the following broad geographic areas that are informed by our wildfire risk models.

112 2022-2023 County Work Area Maps (pge.com).

Distribution

- Geographic Area 1: The top risk areas based on wildfire risk models (HFTD/HFRA);[113]
- Geographic Area 2: The remaining risk areas based on wildfire risk models (remaining HFTD/HFRA areas); and
- Geographic Area 3: Non-HFTD/HFRA.

Transmission

- Geographic Area 1: HFTD/HFRA; and
- Geographic Area 2: Non-HFTD/HFRA.

Table PG&E-7.1.4-4 below identifies key mitigations by Geographic Area for Distribution and Table PG&E-7.1.4-5 below identifies key mitigations PG&E considers by Geographic Area for Transmission.

113 Because different programs have different views of top risk areas, Table PG&E-7.1.4-1 below breaks out a "top risk area" within the HFTD/HFRA where PG&E will focus our efforts for certain programs during the WMP cycle.

TABLE PG&E-7.1.4-4:
PRIORITIZED LIST OF MITIGATIONS BY GEOGRAPHIC AREA – DISTRIBUTION

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			
Asset Inspections	X	X	X
Vegetation Inspections	X	X	X
Weather Stations	X	X	X
Wildfire Cameras	X	X	X
Fire Detection and Alerting System	X	X	X
Operational Mitigations			
Enhanced Powerline Safety Settings	X	X	
Equipment Maintenance and Repair	X	X	X
Pole Clearing	X	X	X
Vegetation Management for Operational Mitigations	X	X	X
Substation Defensible Space	X	X	X
Public Safety Power Shut-off	X	X	X
System Resilience Mitigations			
Undergrounding	X		
Covered Conductor	X	X	
Distribution Pole Replacement and Reinforcement	X	X	X
Distribution Line Removal	X	X	
HFTD/HFRA Open Tag Reduction - Distribution	X	X	
Tree Removal Inventory	X	X	

TABLE PG&E-7.1.4-5:
PRIORITIZED LIST OF MITIGATIONS BY GEOGRAPHIC AREA – TRANSMISSION

Mitigation	Geographic Area 1: HFTD/HFRA	Geographic Area 2: Non-HFTD/HFRA
Comprehensive Monitoring and Data Collection		
Asset Inspections	X	X
Vegetation Inspections	X	X
Weather Stations	X	X
Wildfire Cameras	X	X
Fire Detection and Alerting System	X	X
Operational Mitigations		
Enhanced Powerline Safety Settings	X	X
Equipment Maintenance and Repair	X	X
Pole Clearing	X	X
Substation Defensible Space	X	X
Transmission Integrated Vegetation Management	X	X
Public Safety Power Shut-off	X	X
System Resilience Mitigations		
Transmission Pole Replacement and Reinforcement	X	
Transmission Conductor Replacement	X	
Transmission Line Removal	X	
HFTD/HFRA Open Tag Reduction – Transmission	X	

In Section 7.2.1 below we introduce our portfolio of mitigations. Each of the mitigations described in Section 7.2.1 was evaluated according to the procedures described above and ultimately selected for inclusion in our balanced portfolio. In Section 7.2.1 we discuss mitigations that we evaluated but chose not to pursue.

In Section 8 of this WMP we provide detailed information about all our distribution and transmission wildfire mitigation initiatives, the risks that they reduce, and benefits of implementing them.

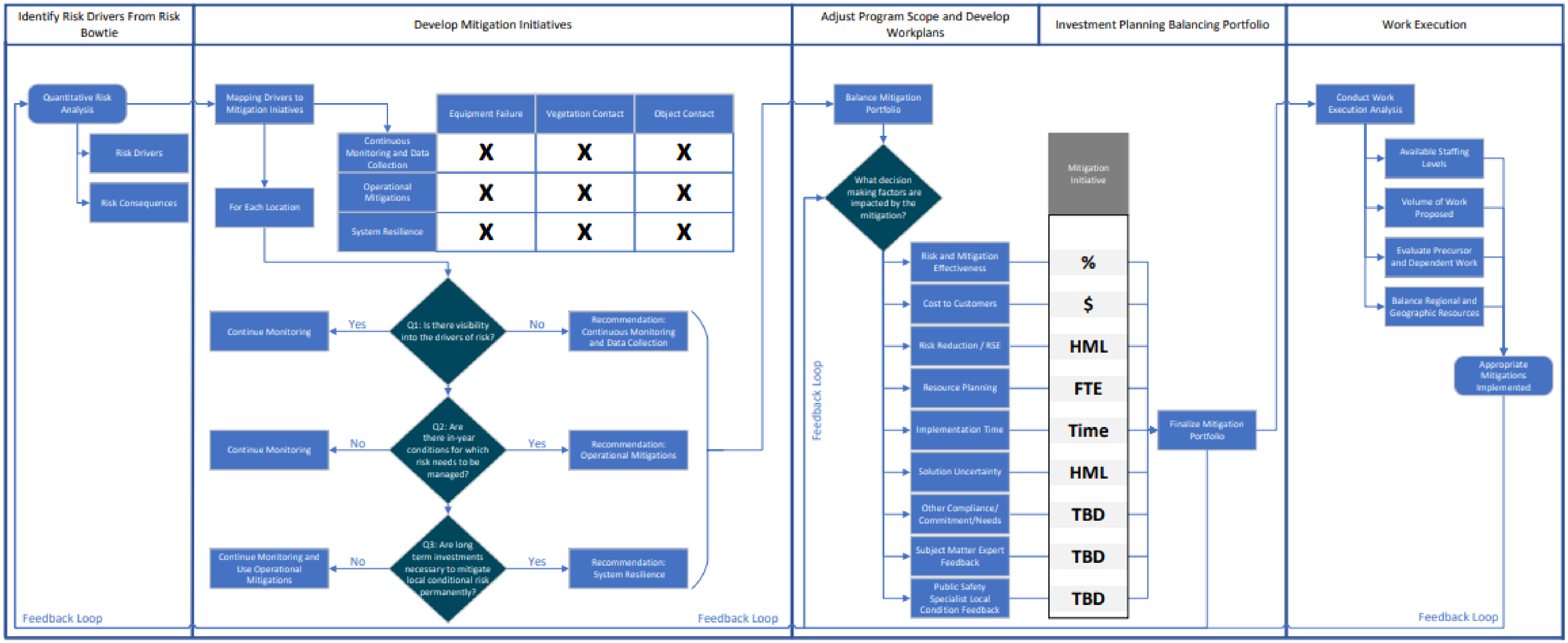
In Section 9 of this WMP we provide detailed information about our PSPS Program and how we use PSPS to mitigate the consequences of wildfire risk.

At the same time PG&E's risk organization and program owners are developing and evaluating the mitigation initiatives, our Investment Planning organization works within its prescribed funding level to begin developing a balanced budget that incorporates wildfire risk reduction work while also funding other priorities such as compliance work, capacity, reliability, and customer work. Funding our wildfire and PSPS mitigation portfolio, and our other priorities, depends in large part on the outcomes of our GRC and Transmission Operator filings. The levels of funding we receive may require us to adjust our workplans during this WMP cycle.

Along with evaluating risk reduction and considering available resources, PG&E also conducts work execution analyses centered around evaluating the number of hours available to execute work based on current staffing levels and the volume and type of work considered. Work Execution also evaluates precursor and dependent work, such as the number of project estimators needed and material availability, to support the forecast. In addition to evaluating available resources in aggregate, PG&E also balances regional and geographic resource availability.

Figure PG&E-7.1.4-1B is an illustration depicting how we develop our balanced mitigation portfolio.

FIGURE PG&E-7.1.4-1B:
DEVELOPING THE BALANCED MITIGATION PORTFOLIO



7.1.4.3 Mitigation Initiative Scheduling

The electrical corporation must report on its schedule for implementing its portfolio of mitigation initiatives. The electrical corporation must describe its preliminary schedules for each initiative and its iterative processes modifying mitigation initiatives (Section 7.1.4.1).

Mitigation initiatives may require several years to implement. For example, relocating transmission or distribution capabilities from overhead to underground may require substantial time and resources. Since mitigation initiatives are undertaken in high-risk regions, the electrical corporation may need interim mitigation initiatives to mitigate risk while working to implement long-term strategies. Some examples of interim mitigation initiatives include more frequent inspections, fire detection and monitoring activities, and PSPS usage. If the electrical corporation's mitigation initiatives requires substantial time to implement, the electrical corporation must identify and deploy interim mitigation initiatives as described in Section 7.2.3.

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

- *How the electrical corporation schedules mitigation initiatives.*
- *How the electrical corporation evaluates whether an interim mitigation initiative is needed and, if so, how an interim mitigation initiative is selected (see Section 7.2.3).*
- *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 initiative is off track and for bringing it back on track.*
- *How the electrical corporation measures the effectiveness of mitigation initiatives (e.g., tracking the number of protective equipment and device settings de-energizations that had the potential to ignite a wildfire due to observed damage/contact prior to re-energization). The mitigation sections of these Guidelines (Section 8) include specific requirements for each mitigation initiative.*

How the Electrical Corporation Schedules Mitigation Initiatives

Our overriding objective when scheduling mitigation initiatives is to ensure that we have built sufficient risk mitigation into the system through Comprehensive Monitoring and Data Collection and Operational Mitigations to keep our communities safe as we develop our long-term resilience programs. The combination of Comprehensive Monitoring and Data Collection programs, such as the Hazard Awareness and Warning Center (HAWC) and wildfire cameras, and Operational Mitigations, like EPSS and VM programs, allow us to manage wildfire risk while implementing long-term System Resilience solutions.

As an example, Figure PG&E-7.1.4-2 below illustrates how PG&E relies on the combination Comprehensive Monitoring and Data Collection programs and Operational Mitigations to manage wildfire risk while System Resilience occurs.

FIGURE PG&E-7.1.4-2:
EXPOSURE AREAS AND EXAMPLES OF MITIGATION COVERAGE

Category	Transmission				Distribution		Secondary		Service	
Sub Category	500 kV	230 kV	115 kV	60-70 kV	3 Wire	4 Wire	UG	OH	OH	
Est. Miles	410	1,680	1,735	1,820	25,540	675	95	3,810		
Ignition Count	4	4	23	31	1,227		93		0	21
Fires > 5,000 Acres	0	1	1	1	11		0		0	0
Fires per 1,000 Miles	25				47					
Comprehensive Monitoring & Data Collection	Continuous Monitoring: Weather Stations, WF Cameras, HAWC									
	Detailed Inspections									
	Vegetation Management Annual and Mid-Cycle Inspections									
	WT Risk Model				WD Risk Model					
Operational Mitigation	PSPS									
	EPSS									
						DCD				
	QEW Onsite Standard									
					Partial Voltage (PV)					
	Vegetation Management Mitigation Programs									
System Reliance					Undergrounding					
				Overhead System Hardening						
	System Hardening Programs									

Note: Data from January 1, 2017 through December 31, 2022.

How the Electrical Corporation Evaluates Whether an Interim Mitigation Initiative Is Needed and, If So, How an Interim Mitigation Initiative Is Selected

When our Comprehensive Monitoring and Data Collection initiatives indicate there is wildfire exposure that cannot be quickly addressed through our suite of long-term resilience initiatives, we identify interim mitigations within the Operational Mitigation category that have the potential to be deployed quickly to address the threat.

Operational Mitigations are selected following the process described in Section 7.1.4.2 above. The list of Operational Mitigations and how we deploy different types of interim mitigations is discussed in Section 7.2.3 below.

Figures PG&E-7.1.4-3, PG&E-7.1.4-4, and PG&E-7.1.4-5 below show approximate dates mitigation initiatives were installed from 2020-2022 and the planned implementation schedule for 2023-2026. The three figures combined show how we have deployed, and will continue to deploy, our portfolio of mitigations to monitor our systems, provide interim risk mitigation, and build more resilience into our systems.

The initiative percent complete is an estimate as of January 2023. The actual amount of work completed will vary over time.

FIGURE PG&E-7.1.4-3:
COMPREHENSIVE MONITORING AND
DATA COLLECTION MITIGATIONS IMPLEMENTATION SCHEDULE

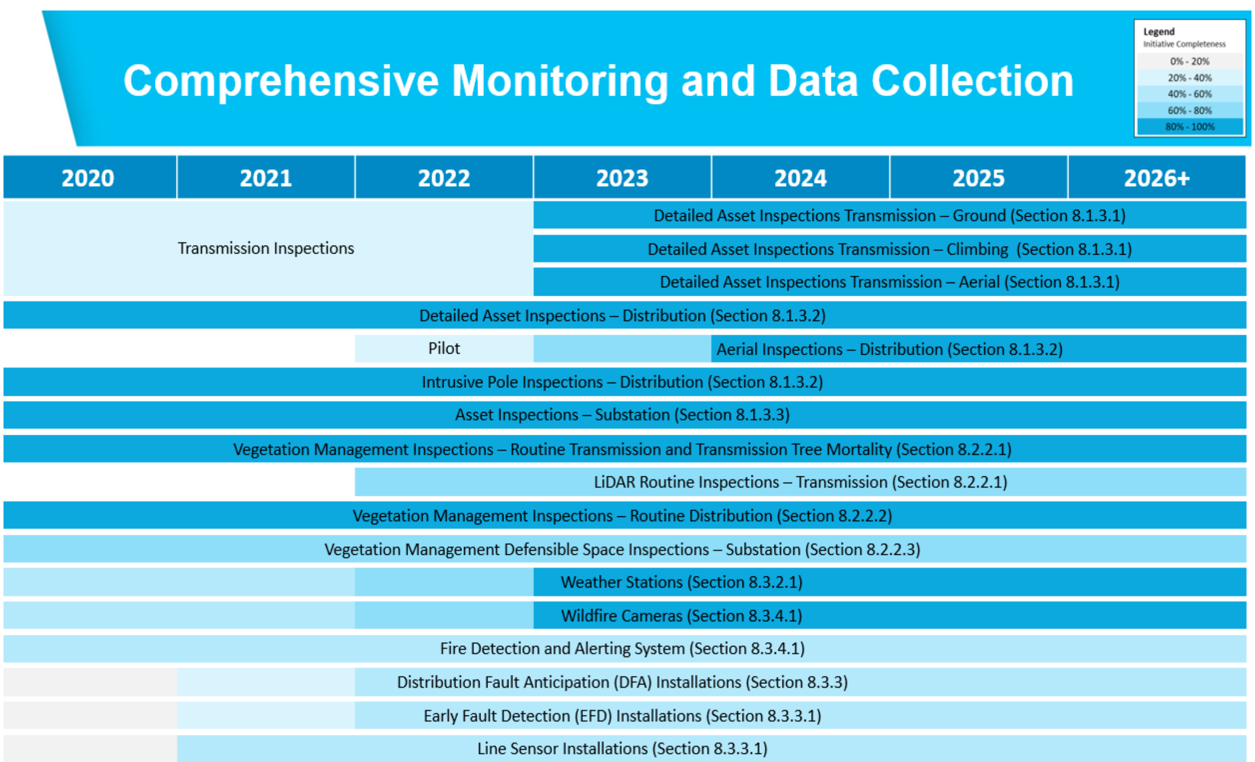


**FIGURE PG&E-7.1.4-4:
OPERATIONAL MITIGATIONS
IMPLEMENTATION SCHEDULES**

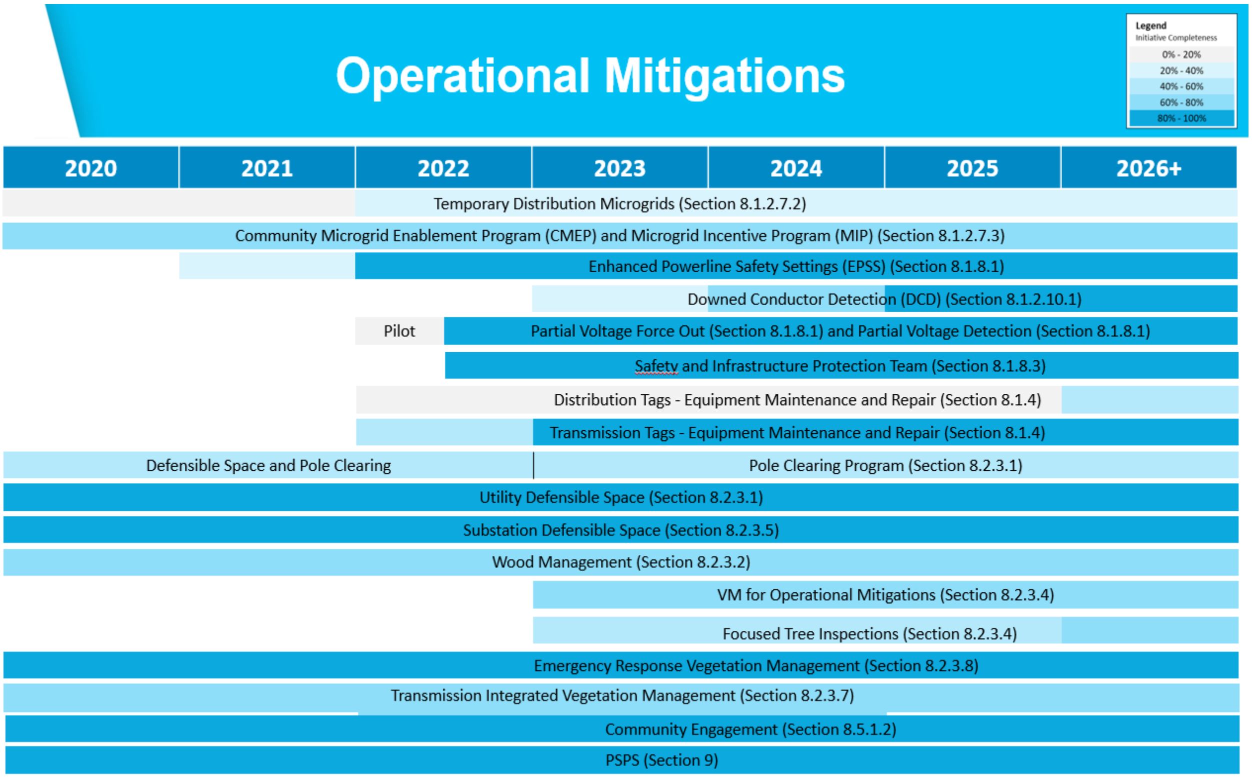
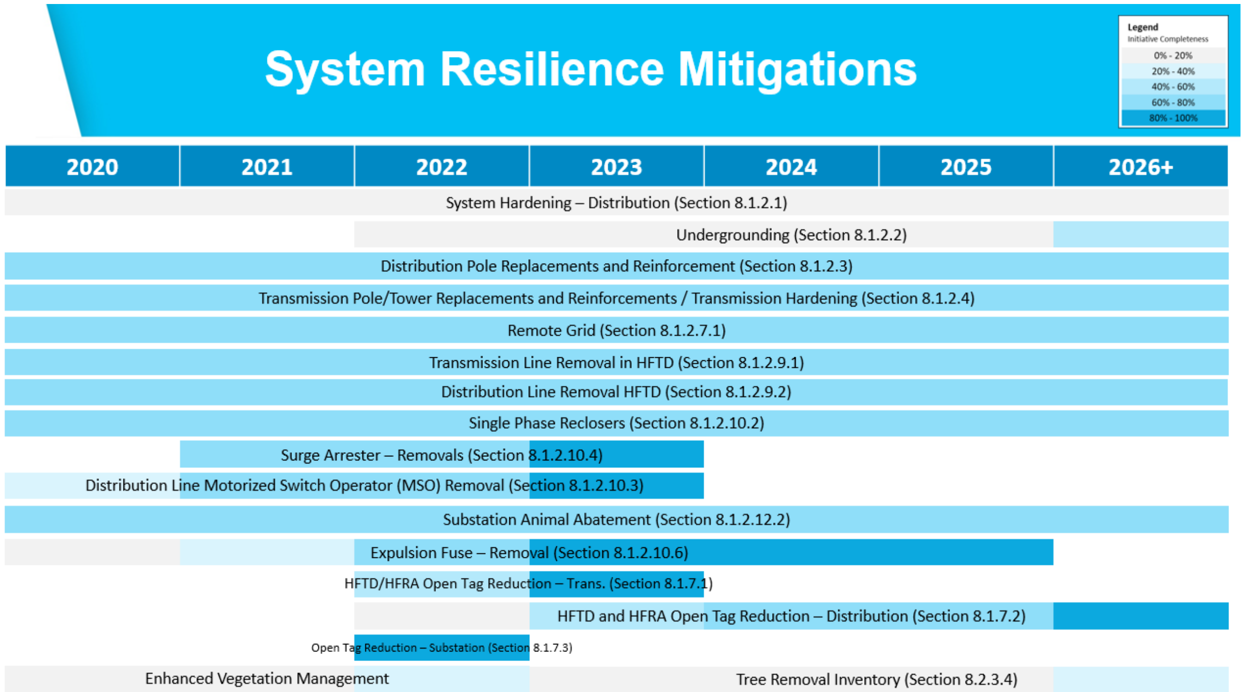


FIGURE PG&E-7.1.4-5:
SYSTEM RESILIENCE MITIGATIONS
IMPLEMENTATION SCHEDULE



How the Electrical Corporation Monitors Its Progress Toward Its Targets Within Known Limitations and Constraints

Teams who are responsible for executing mitigation activities hold weekly schedule validation meetings to confirm that work is meeting the approved program schedule. These meetings provide the forum for stakeholders to provide status updates, communicate changes to schedules and to collaborate to resolve any issues and risks to schedules. Leaders follow the lean performance 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: consistent program monitoring through visual management that shows how we are performing against safety, customer, delivery, and quality; operating reviews focused on identifying and addressing issues and barriers to getting the right work done; resolving issues and negative trends as soon as they are identified; and standardizing effective work processes and best practices.

The Wildfire Weekly Operating Review monitors the progress of our wildfire mitigation activities. The Wildfire Weekly Operating Review has implemented formal tracking programs for these activities. All action items are assigned an owner and due date. We hold a weekly meeting to track the status of items coming out of the WRGSC meetings that are due within the coming 30 days or that are past due. A list of open action items and the status of each are included in the WRGSC meeting materials. Once action items are complete, the WRGSC voting members receive an email confirming completion.

PG&E also monitors WMP progress at the board level. We provide a monthly update to PG&E board members through the board portal. At each quarterly board meeting we provide an update to the Safety and Nuclear Oversight (SNO) committee. SNO committee members are also occasionally invited to attend WRGSC meetings.

How the Electrical Corporation Measures the Effectiveness of Mitigation Initiatives

PG&E uses performance metrics (outcome-based metrics) to measure the effectiveness of our wildfire initiatives. Performance metrics are aligned to two goals.

- Goal 1 – Reduce ignitions in the HFTD and HFRA. Ignition reduction cannot necessarily be attributed to a single mitigation, so we evaluate ignition reduction at the portfolio level.

- Goal 2 – Reduce customer impacts from EPSS and PSPS.

For example, to determine EPSS ignition reductions, PG&E calculates ignition reduction from EPSS based on the following: CPUC Reportable Facility Ignitions in HFTDs on primary distribution conductor on an EPSS enabled zone as compared to the annual average of ignitions during the 2018-20 time period, weather-normalized to when EPSS would have been enabled. Further detail regarding the effectiveness of the EPSS program can be found in Section 8.1.8.1.

In Sections 8 and 9 we provide the performance metrics we use to evaluate the effectiveness of our mitigations in reducing wildfire and PSPS risk.

7.2 Wildfire Mitigation Strategy

Each electrical corporation must provide an overview of its proposed wildfire mitigation strategies based on the evaluation process identified in Section 7.1.

7.2.1 Overview of Mitigation Initiatives and Activities

The electrical corporation must provide a high-level summary of the portfolio of mitigation initiatives across its service territory. In addition, the electrical corporation must describe its reasoning for the proposed portfolio of mitigation initiatives and why it did not select other potential mitigation initiatives.

Additionally, for each mitigation initiative category, the electrical corporation must provide the following:

- *A high-level overview of the selected mitigation initiatives;*
- *An implementation plan, including its schedule and how progress will be monitored; and*
- *How the need for any interim mitigation initiatives was determined and how interim mitigation initiatives were selected (see Section 7.2.3).*

Table 7-3 provides an example of a summary list of mitigation initiative.

In this section we provide a brief overview of our wildfire mitigation initiatives by category included in our WMP. We also provide a reference to the section in this WMP where they are described in more detail. We described how we determine the need for the mitigations included in the portfolio in Section 7.1.4, and how we monitor the mitigations more specifically in Section 7.1.4.3 above.

PG&E's mitigations are generally divided into three categories—Comprehensive Monitoring and Data Collection, Operational Mitigations, and System Resilience—that are broadly defined as:

- Comprehensive Monitoring and Data Collection: Programs designed to provide insight into the condition of PG&E's equipment and the environment;
- Operational Mitigations: Programs designed to manage system risk; and
- System Resilience: Mitigations designed to reduce ignition risk by changing how PG&E's grid is constructed and operated.

Below is a brief overview of the mitigation initiatives contained in our plan that fall into each of these three categories, as well as mitigation initiatives considered but ultimately not chosen for implementation as part of this Plan. In the overview, we also identify which mitigation initiatives are related to specific targets and objectives that we will be reporting throughout the year to Energy Safety.

Not every program associated with a target or objective is introduced in Section 7.2.1. For example, Target GM-01 is aligned to Asset Inspections – Quality Assurance. Because quality assurance is not a mitigation initiative but is instead a program to improve the Asset Inspections initiative, the Asset Inspections – Quality Assurance program is not listed in the Section 7.2.1 overview. The Asset Inspections program itself is introduced in Section 7.2.1.

Following the overview, Tables 7-3-1 and 7-3-2 list all our current Objectives and Targets for the next ten years.

Comprehensive Monitoring and Data Collection

Detailed Asset Inspections Transmission – Ground (See Section 8.1.3.1)

Transmission overhead assets in a HFTD and/or a HFRA are inspected in accordance with the Electric Transmission Preventive Maintenance and/or the Failure Mode and Effects Analysis. These inspections seek to proactively identify pending failures of asset components, which could create a fire ignition. Inspection methodologies include ground, climbing, aerial, infrared (IR), intrusive pole inspection, patrols, switch function tests and pilot inspections. This initiative is aligned to Targets AI-02, AI-04, AI-05, and AI-06 and Objective GM-01.

Detailed Asset Inspections – Distribution (See Section 8.1.3.2)

Distribution overhead assets in HFTD and HFRA are inspected in accordance with the Electric Distribution Preventive Maintenance (EDPM) Manual. PG&E's methods of inspection include detailed ground inspections, ground patrols, IR inspections, intrusive pole inspections, and Light Detection and Ranging (LiDAR) assessments. All inspections seek to proactively identify pending failures of asset components, which could lead to an ignition. This initiative is aligned to Target AI-07 and Objectives GH-03, GM-01 and AI-01.

Intrusive Pole Inspections – Distribution (See Section 8.1.3.2.3)

Intrusive pole inspections, also called Pole Test and Treat, are a way to evaluate in-service wood poles and are conducted on an approximate 10-year cycle for early detection of deterioration. These inspections can be effective in identifying wood poles that need to be replaced before a pole failure, which could result in an ignition event.

Aerial Inspections – Distribution (See Section 8.1.3.2.7)

PG&E plans on conducting Pole Top Drone Inspections during which we will capture approximately 3 to 10 photos of the PG&E structures covering mainly the top 1/3 of the structure. This type of aerial inspection will be focused on eliminating ignition risk from PG&E structures by conducting inspections more quickly. This initiative is aligned to Objective AI-03.

Asset Inspections – Substation (See Section 8.1.3.3.1)

The substation supplemental inspection program is a comprehensive inspection of all the assets located inside substations located within HFTD and HFRA areas. These inspections are designed to identify equipment issues and damage that may adversely impact reliable operations and/or pose a wildfire ignition risk. The supplemental inspection program includes drone-based aerial inspections, ground-based visual inspections, and IR inspections. Substation inspections include transmission, distribution, and hydro generation substations. This initiative is aligned to Targets AI-08, AI-09, and AI-10.

Vegetation Management Inspections – Routine Transmission (See Section 8.2.2.1.1)

Trees or other vegetation that make contact or cross within flash-over distance of high voltage transmission lines can cause phase-to-phase or phase-to-ground electrical arcing, fire ignition, or local, regional, or cascading, grid-level service interruption. PG&E's transmission VM program consists of several different methods for inspecting vegetation in proximity to transmission lines. This initiative is aligned to Objectives VM-09, VM-10 and VM-12.

LiDAR Routine Inspections – Transmission (See Section 8.2.2.1.1)

The Routine North American Electric Reliability Corporation (NERC) Program includes LiDAR inspection, visual verification of findings, and mitigation of vegetation encroachments on approximately 6,800 miles of transmission lines designated by NERC as critical. The Non-Routine NERC Program includes LiDAR inspection, visual verification of findings, and mitigation of vegetation encroachments as well as other vegetation conditions on approximately 11,400 miles of transmission lines not designated as critical by NERC. This initiative is aligned to Target VM-01.

Vegetation Management Inspections – Transmission Tree Morality, Second Patrol (See Section 8.2.2.1.2)

PG&E conducts a Second Patrol aerial LiDAR inspection in the HFTD areas of our system at the height of the vegetation growing season which coincides with the beginning of what is historically the most active part of the California fire season. This patrol allows PG&E to conduct a supplemental assessment of potential tree growth following seasonal rain to reduce the potential of ignitions.

Vegetation Management Inspections – Routine Distribution (See Section 8.2.2.2.1)

Vegetation located close to electrical equipment can cause ignitions by contacting the equipment, either catching fire or dropping a spark that could cause other vegetation to ignite. PG&E's distribution VM program inspects approximately 80,000 miles of overhead distribution electric facilities on a recurring cycle and is designed to comply with state and federal laws and regulations. This initiative is aligned to Objectives VM-09, VM-10, and VM-12.

Vegetation Management Inspections – Distribution, Second Patrol See Section 8.2.2.2.2)

In accord with regulatory requirements and/or PG&E procedures, the VM Second Patrol program performs scheduled patrols approximately six months before or after the routine patrol on overhead primary and secondary distribution facilities. Beginning in 2023, PG&E will use the annual review of AOC, that we committed to doing in RN_PG&E-22-09, to identify areas subject to Second Patrols.

Vegetation Management Defensible Space Inspections – Substation (See Section 8.2.2.3.1)

PG&E assesses the area around Electric Substations in HFTD and HFRA areas to identify potential flammable fuels and vegetation for removal to minimize the potential for ignition spread outside of facilities and to provide improved structure defense capability for firefighting purposes by ensuring there is a safe distance between vegetation and critical infrastructure. Substation inspections include electric and hydro generation substations. This initiative is aligned to Targets VM-05, VM-06, and VM-07.

Weather Stations (See Section 8.3.2.1)

PG&E's weather stations are used year-round to monitor temperatures, wind speeds, wind gusts and relative humidity and are exceptionally crucial during PSPS events. Readings from stations are evaluated in real-time to support decision-making around whether or not to implement PSPS and are used to validate conditions before the weather all-clear is declared.

Wildfire Cameras (See Section 8.3.4.1)

Video cameras allow fast and accurate detection or confirmation of wildfires, which can help operators assess the scope of resource response needed. This initiative is aligned to Objective SA-01.

Fire Detection and Alerting System (See Section 8.3.4.1)

Early fire detection systems, including satellite IR imaging, high-definition video, and land-based IR cameras, are located throughout the entire PG&E service territory including identified HFTD areas.

Distribution Fault Anticipation Installations (See Section 8.3.3.1)

Distribution Fault Anticipation (DFA) are substation-based devices measuring volts, amps, and arcing conditions. They provide detection and assistance in locating faults, abnormal power flow events, and categorization of events. This initiative is aligned to Objective SA-03.

Early Fault Detection Installations (See Section 8.3.3.1)

Early Fault Detection sensors are a sophisticated technology that listens for the RF signal that is generated by partial discharge arcing on AC circuits and uses precision time measurement of events to locate the source along the conductors. EFDs provide early detection of failing equipment and have the potential to detect vegetation encroachment. This initiative is aligned to Objective SA-03.

Line Sensor – Installations (See Section 8.3.3.1)

Line Sensors provide detection and assistance in locating faults. This initiative is aligned to Target SA-02.

Operational Mitigations

Temporary Distribution Microgrids (See Section 8.1.2.7.2) (Interim Mitigation Group 2)[114]

PG&E's temporary distribution microgrids are designed to reduce the number of customers impacted by PSPS events and support community resilience by powering a cluster of shared resources (e.g., commercial corridors and critical facilities within the energized zones) so that those resources can continue serving surrounding residents during PSPS events.

Community Microgrid Enablement Program and Microgrid Incentive Program (See Section 8.1.2.7.3) (Interim Mitigation Group 2)

PG&E introduced the Community Microgrid Enablement Program (CMEP) as part of our proposal to address PSPS mitigation and support energy resilience for our customers and communities. CMEP's approach is to empower communities directly through a combination of technical and financial assistance, as well as through development of the tariffs and agreements necessary to facilitate multi-customer microgrids. Microgrid Incentive Program (MIP) is intended to fund clean community microgrids, with a focus on disadvantaged and vulnerable populations impacted by grid outages.

Downed Conductor Detection (See Section 8.1.2.10.1) (Interim Mitigation Group 3)

High impedance faults are conditions where line-to-ground faults (i.e., downed conductor) do not draw a large enough fault current (a function of contact resistance to ground) that a protective device can reliably sense and trip the circuit offline. These situations can create a potential ignition source. DCD technology can improve the ability to detect and isolate high impedance faults before an ignition can occur. This initiative is aligned to Target GM-06.

Equipment Maintenance and Repair (See Section 8.1.4) (Interim Mitigation Group 2)

PG&E performs maintenance and repair activities on our equipment to ensure that the equipment is properly installed and maintained to prevent operational failures and reduce system risk, including ignition risk.

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114 PG&E divides our Operational Mitigations into three Interim Mitigation groups as described in Section 7.2.3 below.

Enhanced Powerline Safety Settings (See Section 8.1.8.1.1) (Interim Mitigation Group 3)

Enabling EPSS distribution and transmission line protection devices reduces the time it takes for line protective devices such as circuit breakers and line reclosers (LR) to de-energize a powerline when a fault occurs. This more rapid response can prevent potential wildfire ignitions. This initiative is aligned to Objective GM-07.

Partial Voltage Detection (See Section 8.1.8.1) (Interim Mitigation Group 3)

PG&E has enabled single-phase and polyphase SmartMeters™ to send real-time alarms to the Distribution Management System when they detect partial voltage conditions (25 to 75 percent of nominal voltage), or full or partial loss of phase (in polyphase). Detection of partial voltage conditions allows Control Center Operators to dispatch field personnel to locations where equipment may be in a condition that increases wildfire risk. This technology helps PG&E detect and locate a wire down condition within minutes, instead of relying on a customer phone call or employee assessment to provide notification of a wire down. This may reduce the amount of time a line is energized while down (where it can cause an ignition) and allow first responders to extinguish wire-down related ignitions more quickly if they occur.

Partial Voltage Force Out (See Section 8.1.8.1.1) (Interim Mitigation Group 3)

The Partial Voltage Force Out process leverages our extended SmartMeter™ network to help identify and respond to High Impendence faults. When a partial voltage (PV) alarm indicates low SmartMeter™ voltage on two or more SmartMeter™ devices at the fuse level, the Distribution Control Center Operator will force out the next upstream automatic protection device and dispatch response teams to the area of the alarm.

Safety and Infrastructure Protection Team (Section 8.1.8.3) (Interim Mitigation Group 3)

Safety and Infrastructure Protection Team (SIPT) supports resources performing work in HFRAs. SIPT crews consist of two to three International Brotherhood of Electrical-Workers represented employees 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.

Pole Clearing Program (See Section 8.2.3.1) (Interim Mitigation Group 2)

PG&E performs removal of vegetation around select transmission and distribution poles and towers, in accordance with PRC Section 4292, to maintain a firebreak of at least 10 feet in radius (out from the pole) and 8 feet up from the ground. These requirements apply in the state responsibility area during designated fire season. This initiative is aligned to Target VM-02.

Utility Defensible Space (See Appendix D, ACI PG&E-22-23) (Interim Mitigation Group 2)

PG&E developed a Utility Defensible Space (UDS) program in 2021 that addresses reduction or adjustment of lives fuels. UDS expands vegetation clearance around certain poles to extend the firebreak. UDS is not used as extensively as pole clearing but is based on a risk informed prioritization and has a more limited scope.

Wood Management (See Section 8.2.3.2) (Interim Mitigation Group 2)

Utility work on vegetation creates debris and wood products which**,** if left unmanaged, can become fuel for wildfire. PG&E is required to reduce or adjust live fuels as they are generated from programs developed to comply with PRC 4293, General Order 95 Rule 35 and Pub. Util. Code 8386.

Vegetation Management for Operational Mitigations (See Section 8.2.2.2.3) (Interim Mitigation Group 3)

This program is intended to help reduce outages and potential ignitions using a risk informed targeted plan to mitigate potential vegetation contacts based on historic vegetation caused outages on EPSS-enabled circuits. We will initially focus on mitigating potential vegetation contacts in circuit protection zones that have experienced vegetation caused outages. Scope of work will be developed by using EPSS and historical outage data and vegetation failure from the WDRM v3 risk model. EPSS-enabled devices vegetation outages extent of condition inspections may generate additional tree work.

Focused Tree Inspections (See Section 8.2.2.2.5) (Interim Mitigation Group 2)

PG&E is developing AOC in order to better focus VM efforts to address higher risk areas that have experienced higher volumes of vegetation damage during PSPS events, outages and/or ignitions. This initiative is aligned to Objectives VM-03 and VM-11.

Substation Defensible Space (See Section 8.2.3.5) (Interim Mitigation Group 2)

In 2023, Defensible Space is defined by three primary zones of clearance: 0’ to 5’ from energized equipment or building is referred to as Zone 0 or the “Ember – Resistant Zone” and is intended to be void of any combustibles; 5’-30’ surrounding energized equipment and building is called the “Clean Zone” and in most cases is clear of trees and most vegetation; 30’-100’ is the “Reduced Fuel Zone” where vegetation is permitted, if it is reduced or thinned and maintained.

Transmission Integrated Vegetation Management (See Section 8.2.3.7) (Interim Mitigation Group 2)

Integrated VM for transmission promotes desirable, stable, low-growing plant communities that resist invasion by tall growing tree and brush species, using appropriate, environmentally sound, and cost-effective control methods. Integrated VM control methods include a combination of chemical, biological, cultural, mechanical, and/or manual treatments. Integrated VM focuses on reclaimed Transmission-Right-of-Way (ROW) corridors. ROW corridors are placed into the Integrated VM program typically one to two years following reclamation, and periodically reworked when regrowth threshold triggers are met or exceeded.

Emergency Response Vegetation Management (See Section 8.2.3.8) (Interim Mitigation Group 2)

All trees identified for work by pre-inspectors are evaluated for the priority of the required tree work. If vegetation is determined to be an immediate risk to PG&E facilities, described as a Priority 1 Condition in the VM Priority Tag Procedure (TD-7102P-17), the condition will be mitigated within 24 hours of identification as long as conditions are safe for the tree crew to proceed with work.

Community Engagement (See Section 8.5) (Interim Mitigation Group 4)

PG&E hosts safety-focused community engagement events, including regional town halls and community webinars to engage directly with customers. PG&E uses these events to convey local wildfire safety information in advance of wildfire season and events focusing on the impacts that wildfire safety efforts have on the community. PG&E will also host events for specific audiences, including customers with Access and Functional Needs, K-12 schools, in-language webinars, large commercial customers, and for Community Based Organizations. This initiative is aligned to Objectives CO-01 and CO-03.

PSPS Event (See Section 9) (Interim Mitigation Group 3)

A PSPS event consists of the activities directly associated with PG&E's proactive de-energization of our electric transmission and/or distribution lines following a determination of weather-related imminent threats to power line assets and increased risk of catastrophic wildfire. The scope and duration of a PSPS event is based upon PG&E's near-term modeling of weather forecasts and vegetation fire potential. This initiative is aligned to Targets PS-06 and PS-07 and Objectives PS-01 through PS-05.

System Resilience

Covered Conductor Installation – Distribution (See Section 8.1.2.1)

Covered conductor installation, also referred to as Overhead System Hardening, involves the replacement of bare overhead primary (high voltage) conductor and associated framing with conductor insulated with abrasion-resistant polyethylene coatings (sometimes referred to as covered conductor or tree wire). Installing covered conductor can help reduce the likelihood of faults due to line-to-line contacts, tree-branch contacts, and faults caused by animals. This initiative is aligned to Target GH-01 and Objective GH-02.

10K Undergrounding (See Section 8.1.2.2)

Undergrounding consists of relocating existing high risk overhead distribution lines underground. Undergrounding effectively eliminates the ignition risk for overhead lines that have been placed underground. The underground alternative is considered as the preferred mitigation when addressing PSPS impacts, ingress and egress concerns, and tree fall-in risk. This initiative is aligned to Target GH-04.

Distribution Pole Replacements and Reinforcement (See Section 8.1.2.3)

Distribution poles are inspected and evaluated to determine whether their condition allows them to support pole mounted equipment and safely keep energized conductors in the air. When early deterioration is identified, the distribution poles are remediated through replacement or reinforcement, which reduces the risk of ignition.

Transmission Pole/Tower Replacements and Reinforcements (See Section 8.1.2.4)

Maintenance, repair, life extension, and replacement of transmission structures in HFTD areas are integral means of mitigating risk associated with wildfire.

Transmission Conductor Replacement (See Section 8.1.2.5.1)

PG&E does not have a separate program for overhead system component hardening that specifically aligns with the updated Energy Safety definition of traditional overhead hardening. Transmission conductor replacement projects focus on the risk associated with transmission line conductor failure, which may lead to wildfire ignition. There are two levels of projects for transmission conductor hardening: larger projects in the Targeted Line Rebuild program; and smaller projects in the Dispersed Conductor Component (Splice) Hardening and Conductor Segment Replacements. These initiatives are aligned to Targets GH-05 and GH-06.

Remote Grid (See Section 8.1.2.7.1)

Removal of an existing overhead distribution line fully eliminates the fire risk associated with that line. Throughout PG&E's service territory, pockets of isolated small customer loads are currently served via long electric distribution feeders, some of which traverse HFTD areas and require significant annual maintenance and vegetation management. The Remote Grid Program will remove these long feeders and serve customers from a Remote Grid.

Distribution Protection Devices (See Section 8.1.2.8.1)

Install additional line reclosers and Fuse Savers on the highest impacted protective zones to reduce the EPSS reliability impact. These will be installed in locations that are within the HFRA or protect equipment within the HFRA. This initiative is aligned to Target GH-07.

Transmission Line Removal in HFTD (See Section 8.1.2.9.1)

PG&E investigates potentially idle transmission facilities. When these facilities are identified and confirmed to be within an HFTD area with no operational needs, they are prioritized for de-energization, grounding, and/or removal. This initiative is aligned to Target GH-05.

Distribution Line Removal in HFTD (See Section 8.1.2.9.2)

PG&E investigates potentially idle distribution facilities and determines if they can be permanently removed from service. Line removal mitigates ignition risk, specifically for equipment and conductor.

Single Phase Reclosers (See Section 8.1.2.10.2)

A single phase recloser is a flexible, cost-effective, intelligent device which can replace fuses and has the capability to trip all phases (i.e., open and stop power flowing through all two or three phases if just one phase experiences a fault), reducing 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.

Motor Switch Operator Replacement (See Section 8.1.2.10.3)

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 crews identified a risk that some MSO switches were reported to exhibit an arc flash during operation and PG&E halted further installations of MSO switches in late 2019. This activity replaces the MSO switches with reclosers, subsurface equipment, and other vacuum switch equipment that is approved for current usage in HFTD. This initiative is aligned to Target GH-09.

Surge Arrester – Removals (See Section 8.1.2.10.4)

The Non-Exempt Surge Arrester Replacement program replaces non-exempt surge arresters with exempt surge arresters and corrects abnormal grounding issues where necessary. Exempt surge arresters are designed to reduce the potential for release of electrical arcs, sparks, or hot material during operation. This initiative is aligned to Target GH-08.

Expulsion Fuse – Removal (See Section 8.1.2.10.5)

In most cases, the Expulsion Fuse Replacement Program replaces non-exempt fuses with exempt fuses in HFTD and HFRA regions. Exempt fuses are designed to reduce the potential for release of electrical arcs, sparks, or hot material during operation. This initiative is aligned to Target GH-10.

Other Grid Topology Improvements to Mitigate PSPS – Distribution (See Section 8.1.2.11.2)

Installing remotely operable SCADA sectionalizing devices and manually operated sectionalizing devices on the distribution system supports PG&E's ability to segment the distribution circuits close to designated meteorology shut-off polygons to reduce the customer impact and the scope of PSPS events.

Avian Protection (See Section 8.1.2.12.1)

PG&E has an Avian Protection Plan that is designed to protect the avian population from contacting electrical components in our service territory. The plan applies to both the transmission and distribution overhead electrical facilities. Avian protection measures may also improve system reliability, safety, and ignition risk.

Substation Animal Abatement (See Section 8.1.2.12.2)

PG&E employs a substation animal abatement program focused on mitigating animal-related contact events within substations. This program 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.

HFTD and HFRA Open Tag Reduction – Transmission (See Section 8.1.7.1)

Prioritization of open work orders (notifications) based on priority levels A, E, and F defined in the Electric Transmission Line Guidance for Setting Priority Codes Procedure (TD-8123-103). Ignition-related notifications in HFTD and HFRA have a higher priority than non-HFTD and non-HFRA and non-ignition-related notifications. This initiative is aligned to Target GM-02.

HFTD and HFRA Open Tag Reduction – Distribution (See Section 8.1.7.2)

PG&E uses a risk-informed prioritization approach to address the highest risk issues on our system. Maintenance tags generated through our inspection programs are assigned a priority based on the potential safety impact. Open work order (tags or notifications) prioritization uses priority levels the A, B, E, F, and H that are defined in the Electric Distribution Preventive Maintenance Manual. This initiative is aligned to Target GM-03 and Objectives GM-04 and GM-05.

Open Tag Reduction – Substation (See Section 8.1.7.3)

PG&E performs corrective repairs and equipment replacements identified through maintenance and inspections of substations located in HFTD areas. This work is intended to correct deficiencies identified to ensure that substation equipment operates as designed and mitigates the risk of failure. Corrective work is prioritized and completed based on equipment condition and risk of failure.

Tree Removal Inventory (See Section 8.2.2.2.4)

This is a long-term program intended to eventually work down trees that were previously identified through EVM inspections. Under the Tree Removal Inventory Program, we will re-inspect and evaluate the condition of previously identified trees and determine if they should remain in the inspection program or be identified for removal. This initiative is aligned to Target VM-04.

Other Mitigations Considered

As described in Section 7.1.2 above, the WRGSC considers various potential mitigations. Certain mitigations evaluated by the WRGSC are not pursued or, after an initial pilot project, are further evaluated, but not ultimately implemented. Mitigations that the WRGSC considered, but did not select for this WMP period, include the following:

Rapid Earth Fault Current Limiter (See Section 8.1.8.1.3.1)

Rapid Earth Fault Current Limiter (REFCL) technology mitigates ignitions from line-to-ground faults such as wire down or tree contacts. High-impedance, line-to-ground faults on distribution circuits are difficult to detect with traditional overcurrent protection and can become an ignition source.

Under EPIC 3.15, "Proactive Wires Down Mitigation Demonstration Project (Rapid Earth Fault Current Limiter)", PG&E initiated a REFCL demonstration project in 2018 at the Calistoga substation. After initial positive tests, the Calistoga REFCL pilot demonstration was stalled due to the failure of the substation REFCL equipment. In addition, PG&E had difficulty obtaining replacement equipment from various overseas suppliers due to supply chain issues and the ongoing Coronavirus pandemic. Thus, the REFCL technology could not be fully evaluated beyond the initial testing. More recently, PG&E has made progress on our REFCL pilot project including completing changes to the substation equipment after encountering equipment failures. PG&E has performed successful stage fault tests of the REFCL system and is in the process of reviewing the test data to evaluate REFCL's wildfire risk reduction for ground faults on distribution circuits.

While PG&E is looking at opportunities for REFCL deployments in our distribution substations to mitigate wildfire risk and evaluating combinations of REFCL with EPSS and other mitigations, implementing it would require significant and costly changes to the grid. Instead of making costly changes to the grid, we are moving forward with more cost-effective solutions such as DCD and Partial Voltage Detection.

Distribution, Transmission, and Substation: Fire Action Schemes and Technology

Distribution, Transmission, and Substation: Fire Action Schemes and Technology is a technology developed internally at PG&E. It uses fraction of a second technologies to detect an object (such as a falling branch) approaching an energized power line and respond quickly to shut off power before the object impacts the line. We will complete the in-progress installations on our transmission system and continue to evaluate its effectiveness before implementing the program on the distribution system.

Enhanced Vegetation Management (See Section 8.2.2.2.6)

We will transition away from our EVM program after 2022. PG&E evaluated the program's effectiveness compared to the mitigation effectiveness provided by EPSS. We determined that EPSS is more effective at mitigating wildfire risk at a lower cost as shown by comparing the RSEs for the two programs: at the time we filed the 2023

GRC, the RSE for EVM was 14.5 compared to the EPSS RSE of 105.7.[115] While we are not adding new circuit segments to the EVM program we will maintain previously completed segments through the Routine VM program unless lines are undergrounded.

Distribution Infrared Inspections

In 2023, PG&E will be focusing on re-evaluating role of IR within PG&E's broader overhead inspections programs as well the standards and processes supporting the program. We will consider the effectiveness of this technology compared to other inspection methods and how and when it might be best deployed. Options may include focusing the inspection to detect suspected failure modes on certain structures or components and returning to non-HFTD areas instead of performing inspections in HFTD on a mileage basis.

In 2023, PG&E will be deploying IR inspections on an as-needed basis to examine areas of emerging concern. For example, we may deploy IR inspections to complete an extent of condition evaluation for a failure that can be detected by IR.

Utility Defensible Space (See Appendix D, ACI PG&E-22-23)

In the Final Decision on PG&E's 2022 WMP Update, Energy Safety stated that while it believes "UDS is effective, Energy Safety does not consider this activity as a long-term solution. Energy Safety would like to see PG&E decrease [our] UDS program over time as [we] implement other mitigations, such as system hardening and undergrounding."[116] PG&E is required to report on progress made to reduce the need for the UDS program in its 2023 WMP.[117]

PG&E's UDS program addresses reduction or adjustment of lives fuels by expanding vegetation clearance around certain poles to extend the firebreak. PG&E will comply with Energy Safety's direction to decrease the UDS program over time and instead rely on other mitigations.

Line Sectionalizing for PSPS

PG&E has completed our transmission and distribution PSPS line sectionalizing programs. Because there is limited incremental benefit to install additional switches, we are not including these mitigation initiatives in this WMP.

Tables 7-3-1 and 7-3-2: PG&E's Objectives and Targets

As discussed above, we have set specific targets and objectives for our mitigation initiatives in this WMP period (2023-2025) and beyond pursuant to Energy Safety's Guidelines. In Tables 7-3-1 and 7-3-2 below, we list all our objectives and targets over the next 10 years. Our outlook will continue to change as our mitigation portfolio, risk analysis, and emerging technology evolves over this period. We will continue to share

115 A.21-06-021, Exhibit (PG&E-4), pp. 3-39 to 3-40, Table 3-4, lines 1 and 30.

116 OEIS Docket #2022-WMP, Final Decision on PG&E's 2022 WMP (Nov. 10, 2022) p. 118.

117 See ACI PG&E-22-23.

updates to our Objectives and Targets in subsequent Annual WMP updates, quarterly and annual compliance reports, as well as Change Orders requests, where applicable.

For additional context for Tables 7-3-1 and 7-3-2 below, we note the following:

1. Reporting: Unless changed through Energy Safety's Change Order process, PG&E will use the Objectives and Targets in Tables 7-3-1 and 7-3-2 below for quarterly compliance reporting including the Quarterly Data Report (QDR), Quarterly Notification (QN), and the Annual Report on Compliance (ARC). It is also important to note that throughout this 2023-2025 WMP, we discuss current plans for wildfire-related activities in addition to the Objectives and Targets in these two tables. The timing and scope of these additional activities and work may change. We will not be reporting on these plans or activities in our QDR, QN, or ARC because they are not Targets nor Objectives but are descriptions of plans and activities in our 2023-2025 WMP to provide a complete picture of our mitigation activities.

2. Table 7-3-1 Objective Information Summary: In Table 7-3-1, we are providing the category for the WMP objective (Category), the objective name, the applicable Initiative Tracking ID that correlates with the associated initiative in Section 8 or 9 (Initiative Tracking ID), a description of the objective (Objective Description), the planned due date for the objective (Completion Date), and the location in Section 8 or 9 where the additional content required for the objectives is located (Location in the WMP). In the associated Objective tables in Section 8 or 9 , referenced in "Location in the WMP" field, we also provide the "Applicable Regulations, Codes, Standards, and Best Practices", "method of verification", and "section and page #" references; however, these columns are not a part of the Objective. Instead, the controlling Objective information is in the "Objective Description" and "Completion Date" columns.

3. Table 7-3-2 Target Information Summary: In Table 7-3-2, we are providing the category for the WMP target (Category), the target name and ID (Target Name/ID), the applicable Initiative Tracking ID that correlates with the associated initiative in Section 8 or 9 (Initiative Tracking ID), a description of the Target for each applicable year (2023 Target & Unit, 2024 Target & Unit, 2025 Target & Unit), and the location in Section 8 or 9 where the additional content required for targets is located (Location in the WMP). In the associated Target tables in Section 8 or 9 , referenced in "Location in the WMP" field, we also provide the "% Risk Impact", and the method of verification; however, these columns are not a part of the Target. Instead, the controlling target information is in the "Target & Unit" columns for each respective year. Additionally, as specified in the Technical Guidelines, quarterly targets are also specified in Section 8 for inspections and PSPS outreach. Due dates for annual targets are calendar year end unless stated otherwise.

4. External Factors: All targets and objectives in the below Table 7-3-1 and Table 7-3-2 are subject to External Factors which represent reasonable circumstances which may impact execution against targets or objectives including, but not limited to, physical conditions, landholder refusals, environmental delays, 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.

5. HFTD, HFRA, Buffer Areas: Unless stated otherwise, all initiative work described in Table 7-3-2 involves work or audits on units or equipment located in, traversing, energizing, or protecting units or equipment in HFTD, HFRA, or Buffer Zone areas

6. Utility Initiative Tracking ID: We are including Initiative Tracking IDs for each section that has associated targets and objectives. Table 7-3-1 and Table 7-3-2 display the Tracking IDs we are implementing to tie the targets and objectives to the narratives and initiatives in the WMP and that will also be used for reporting such as in the QDR. For any initiative without a target or an objective we have not included an Initiative Tracking ID.

TABLE 7-3-1:
PG&E'S WMP OBJECTIVES

WMP Category	Objective Name	Initiative Tracking ID	Objective Description	3-Year/ 10-Year Outlook	Completion Date	Location in WMP
Grid Design, Operations and Maintenance	Evaluate Covered Conductor Effectiveness	GH-02	Update the covered conductor recorded effectiveness calculation using 2023 and 2024 outage data on the lines that have Covered Conductors for consideration in future system hardening workplans.	Within 3 years	3/29/2024 (2023 data) 3/31/2025 (2024 data	Section 8.1.1.1 Objectives, pp. 318 to 323
Grid Design, Operations and Maintenance	Evaluate and Implement Covered Conductor Effectiveness Impact on Inspections and Maintenance Standards	GH-03	Evaluate the output of the Phase 1 and Phase 2 covered conductor effectiveness study to: (1) determine the impacts of the study on the maintenance and inspections standards for deployed covered conductor assets; and (2) update TD-2305M-JA02 (overhead inspections job aid), as needed.	Within 3 years	12/31/2023	Section 8.1.1.1 Objectives, pp. 318 to 323
Grid Design, Operations and Maintenance	Retainment of Inspectors and Internal Workforce Development	AI-01	1. Develop a plan to increase retention over time for trained and qualified inspectors. 2. Develop a plan to focus on increasing and sustaining a consistent, year-over-year internal workforce that builds on existing experience and mentors new employees for asset inspections.	Within 3 years	12/31/2025	Section 8.1.1.1 Objectives, pp. 318 to 323
Grid Design, Operations and Maintenance	Develop Distribution Aerial Inspections program	AI-03	Evaluate the continued use of aerial inspections for distribution overhead equipment.	Within 3 years	12/31/2023	Section 8.1.1.1 Objectives, pp. 318 to 323

TABLE 7-3-1:
PG&E'S WMP OBJECTIVES
(CONTINUED)

WMP Category	Objective Name	Initiative Tracking ID	Objective Description	3-Year/ 10-Year Outlook	Completion Date	Location in WMP
Grid Design, Operations and Maintenance	Filling Asset Inventory Data Gaps	AI-11	Populate missing age data in the Asset Registry (using "Installation Date" data element as a proxy) to 90 percent weighted average across risk prioritized distribution and transmission equipment.	Within 3 years	12/31/2025	Section 8.1.1.1 Objectives, pp. 318 to 323
Grid Design, Operations and Maintenance	Asset Inspections - Quality Assurance	GM-01	Perform annually, year-round Transmission and Distribution system inspection quality assurance audits of "QC complete" locations in HFTD areas. Statistically valid methodology parameters, such as a confidence level of 95 percent and 5 percent margin of error, will be utilized.	Within 3 years	12/31/2023 12/31/2024 12/31/2025	Section 8.1.1.1 Objectives, pp. 318 to 323
Grid Design, Operations and Maintenance	HFTD/HFRA Open Tag Reduction – Backlog Elimination – 3 Year Plan	GM-04	Eliminate the backlog* of open distribution non-pole ignition risk tags. *Backlog 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.	Within 3 years	12/31/2025	Section 8.1.1.1 Objectives, pp. 318 to 323
Grid Design, Operations and Maintenance	HFTD/HFRA Open Tag Reduction – Backlog Elimination – 7 Year Plan	GM-05	Eliminate the backlog* of open distribution pole ignition risk tags. *Backlog 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.	Within 10 years	12/31/2029	Section 8.1.1.1 Objectives, pp. 318 to 323
Grid Design, Operations and Maintenance	Updates on EPSS Reliability Study	GM-07	Provide annually an updated EPSS reliability impact study per ACI PG&E-22-32	Within 3 years	2/15/2024 (For 2023 data) 2/15/2025 (For 2024 data)	Section 8.1.1.1 Objectives, pp. 318 to 323

TABLE 7-3-1:
PG&E'S WMP OBJECTIVES
(CONTINUED)

WMP Category	Objective Name	Initiative Tracking ID	Objective Description	3-Year/ 10-Year Outlook	Completion Date	Location in WMP
					2/15/2026 (For 2025 data)	
Vegetation Management and Inspection	Focused Tree Inspection Program	VM-03	1. Identify the AOC by developing a collaborative, cross-functional team to evaluate the service territory with electric overhead assets and create system wide map that includes Vegetation Management AOCs. 2. Initiate a pilot program in at least one AOC. 3. Fully implement AOC cross-functional team to implement guidelines across all AOCs. Determine value of a multi-year historical tree data set.	Within 3 years	1. 12/01/2023 2. 12/01/2023 3. 12/31/2025	Section 8.2.1.1 Objectives, pp. 493 to 498
Vegetation Management and Inspection	Constraint Resolution Procedural Guideline	VM-09	1. Develop a process of centralizing constraints resolution. As part of the build out of the centralized constraints team, three major categories will be addressed: customer constraints, environmental constraints (including internal PG&E procedures required to perform work) and permitting constraints (including both Land and Environmental permits). PG&E will consider creating a "right tree-right place" program, as part of the centralize Constraints Resolution process.	Within 3 years	1. 12/31/2023 2. 12/31/2025	Section 8.2.1.1 Objectives, pp. 493 to 498

TABLE 7-3-1:
PG&E'S WMP OBJECTIVES
(CONTINUED)

WMP Category	Objective Name	Initiative Tracking ID	Objective Description	3-Year/ 10-Year Outlook	Completion Date	Location in WMP
			2. For each major constraint category build a process for addressing each constraint type, implement the new process, and create metrics to track each constraint type. Reporting will track total constraints by type and the time it takes to resolve a constraint after it has been identified.			
Vegetation Management and Inspection	Inspection in HFTD and HFRA supporting key vegetation management initiatives	VM-10	Continue multiple inspection activities in HFTD and HFRA supporting key vegetation management initiatives	Within 10 years	12/31/2032	Section 8.2.1.1 Objectives, pp. 493 to 498
Vegetation Management and Inspection	Enhance and refine Focus Tree Inspection – Areas of Concern (AOC)	VM-11	Enhance and refine Focus Tree Inspection - Areas of Concern (AOC) development criteria and application of the AOCs to vegetation management programs	Within 10 years	12/31/2032	Section 8.2.1.1 Objectives, pp. 493 to 498
Vegetation Management and Inspection	Evaluate emerging technologies	VM-12	Evaluate emerging technologies to enhance focus of and streamline execution of vegetation management inspections	Within 10 years	12/31/2032	Section 8.2.1.1 Objectives, pp. 493 to 498
Situational Awareness and Forecasting	AI in Wildfire Cameras	SA-01	Enable Artificial Intelligence processing of Wildfire Camera Data to provide automated wildfire notifications in the internal PG&E monitoring tool (Wildfire Incident Viewer).	Within 3 years	6/30/2023	Section 8.3.1.1 Objectives, pp. 565 to 568

TABLE 7-3-1:
PG&E'S WMP OBJECTIVES
(CONTINUED)

WMP Category	Objective Name	Initiative Tracking ID	Objective Description	3-Year/ 10-Year Outlook	Completion Date	Location in WMP
Situational Awareness and Forecasting	EFD and DFA Reporting	SA-03	Develop scalable processes to: (a) analyze alarms and alerts from Early Fault Detection (EFD) and DFA sensors; (b) conduct field investigation and reporting; (c) track identified mitigations to completion; and (d) track effectiveness of issue identification and remediation using EFD/DFA technologies.	Within 3 years	12/31/2023	Section 8.3.1.1 Objectives, pp. 565 to 568
Situational Awareness and Forecasting	FPI and IPW Modeling – Revision Evaluation	SA-04	Evaluate enhancements to the FPI model and the Ignition Probability Weather model. This involves testing new features and types of model configurations that could improve model skill. At present we do not know if model skills can be improved but we will attempt to do so.	Within 3 years	12/31/2023	Section 8.3.1.1 Objectives, pp. 565 to 568
Situational Awareness and Forecasting	Evaluate FPI and IPW Modeling enhancements in 2023 - 2025	SA-05	Evaluate enhancements to the FPI (Fire Potential Index) model and the IPW (Ignition Probability Weather) model in the 2023-2025 period. This work involves testing new features and types of model configurations that could improve model forecasting ability. For example, one of the features that will be evaluated for inclusion in the IPW model is the use of covered conductor on the system.	Within 3 years	12/31/2025	Section 8.3.1.1 Objectives, pp. 565 to 568

TABLE 7-3-1:
PG&E'S WMP OBJECTIVES
(CONTINUED)

WMP Category	Objective Name	Initiative Tracking ID	Objective Description	3-Year/ 10-Year Outlook	Completion Date	Location in WMP
Situational Awareness and Forecasting	Evaluate FPI and IPW Modeling enhancements in 2026 - 2032	SA-06	Evaluate enhancements to the FPI (Fire Potential Index) model and the IPW (Ignition Probability Weather) model in the 2026-2033 period. This work involves testing new features and types of model configurations that could improve model forecasting ability.	Within 10 years	12/31/2032	Section 8.3.1.1 Objectives, pp. 565 to 568
Emergency Preparedness Plan	Complete PSPS and Wildfire Tabletop and Functional Exercises	EP-01	Complete PSPS and Wildfire Tabletop and Functional Exercise annually in compliance with the guiding principles of the Homeland Security Exercise Evaluation Program.	Within 3 years	11/30/2023 11/30/2024 11/30/2025	Section 8.4.1.1 Objectives, pp. 623 to 628
Emergency Preparedness Plan	Maintain all hazards planning and preparedness program in 2023-2025	EP-02	Maintain the all hazards planning and preparedness program to provide emergency response and safely and expeditiously restore service.	Within 3 years	12/31/2025	Section 8.4.1.1 Objectives, pp. 623 to 628
Emergency Preparedness Plan	Maintain all hazards planning and preparedness program in 2026-2033	EP-03	Maintain the all hazards planning and preparedness program to provide emergency response and safely and expeditiously restore service.	Within 10 years	12/31/2032	Section 8.4.1.1 Objectives, pp. 623 to 628
Emergency Preparedness Plan	Expand all hazards planning to include additional threats and scenarios in 2023-2025	EP-04	Expand the all hazards planning program to include additional threats and scenarios.	Within 3 years	12/31/2025	Section 8.4.1.1 Objectives, pp. 623 to 628
Emergency Preparedness Plan	Expand all hazards planning to include additional threats and scenarios in 2026-2032	EP-05	Expand the all hazards planning program to include additional threats and scenarios.	Within 10 years	12/31/2032	Section 8.4.1.1 Objectives, pp. 623 to 628

TABLE 7-3-1:
PG&E'S WMP OBJECTIVES
(CONTINUED)

WMP Category	Objective Name	Initiative Tracking ID	Objective Description	3-Year/ 10-Year Outlook	Completion Date	Location in WMP
Community Outreach and Engagement	Community Engagement - Meetings	CO-01	Hold community engagement meetings within the five PG&E regions of service that will include, but are not limited to, a mix of webinars, open houses, town halls, and/or answer centers.	Within 3 years	9/30/2023 9/30/2024 9/30/2025	Section 8.5.1.1 Objectives, pp. 718 to 721
Community Outreach and Engagement	Community Engagement – Meetings in 2026-2032	CO-03	Continue to hold community engagement meetings within the five PG&E regions of service. This work will include, but not be limited to, a mix of webinars, open houses, town halls, and/or answer centers.	Within 10 years	12/31/2032	Section 8.5.1.1 Objectives, pp. 718 to 721
PSPS	Evaluate enhancements for the PSPS Transmission guidance	PS-01	Evaluate enhancements for the PSPS Transmission guidance to enhance focus of PSPS events.	Within 3 years	12/31/2025	Section 9.1.3 Objectives, pp. 756 to 759
PSPS	Evaluate incorporation of approved IPW enhancements into the PSPS Distribution guidance	PS-02	Evaluate incorporation of approved IPW enhancements into the PSPS Distribution guidance to enhance focus of PSPS events.	Within 3 years	12/31/2025	Section 9.1.3 Objectives, pp. 756 to 759
PSPS	Evaluate enhancements for the PSPS Transmission guidance	PS-03	Evaluate enhancements for the PSPS Transmission guidance to enhance focus of PSPS events.	Within 10 years	12/31/2032	Section 9.1.3 Objectives, pp. 756 to 759
PSPS	Evaluate incorporation of approved IPW enhancements into the PSPS Distribution guidance	PS-04	Evaluate incorporation of approved IPW enhancements into the PSPS Distribution guidance to enhance focus of PSPS events.	Within 10 years	12/31/2032	Section 9.1.3 Objectives, pp. 756 to 759

TABLE 7-3-1:
PG&E'S WMP OBJECTIVES
(CONTINUED)

WMP Category	Objective Name	Initiative Tracking ID	Objective Description	3-Year/ 10-Year Outlook	Completion Date	Location in WMP
PSPS	Evaluate the transition of the Portable Battery Program to permanent battery solutions	PS-05	Evaluate the transition of the Portable Battery Program to permanent battery solutions for PG&E customers at risk of PSPS or EPSS, focusing on but not limited to AFN, MBL, and self-identified vulnerable populations.	Within 10 years	12/31/2032	Section 9.1.3 Objectives, pp. 756 to 759

TABLE 7-3-2:
PG&E'S WMP TARGETS

Category	Target Name	Initiative Activity Tracking ID	2023 Target & Unit	2024 Target & Unit	2025 Target & Unit	Location in WMP (Section)
Grid Design, Operations and Maintenance	System Hardening – Distribution	GH-01	Complete 420 circuit miles of system hardening work which includes overhead system hardening, undergrounding, and removal of overhead lines in HFTD, HFRA, or buffer zone areas, except for any mileage being undergrounded and tracked separately as part of our Butte County Rebuild and other Community Rebuild efforts.	Complete 470 circuit miles of system hardening work which includes overhead system hardening, undergrounding, and removal of overhead lines in HFTD, HFRA, or buffer zone areas, except for any mileage being undergrounded and tracked separately as part of our Butte County Rebuild and other Community Rebuild efforts.	Complete 580 circuit miles of system hardening work which includes overhead system hardening, undergrounding, and removal of overhead lines in HFTD, HFRA, or buffer zone areas except for any mileage being undergrounded and tracked separately as part of our Butte County Rebuild and other Community Rebuild efforts.	Section 8.1.1.2 Targets, pp. 324 to 333
	Surge Arrestor – Removals	GH-08	Remove 663 non-exempt surge arrestors (based on the known population as of 01/12/2023) where known grounding issues exist. If no non-exempt surge arrestor is identified at a location during pre-field work, the unit will be resolved, and the notification will be canceled. Canceled notifications will count towards this target.	N/A	N/A	Section 8.1.1.2 Targets, pp. 324 to 333
	Distribution Line MSO – Replacements	GH-09	Replace or remove 20 MSOs (from the 47 identified as of January 26, 2023).	Replace or remove the remaining MSOs from the 47 identified, as of January 26, 2023.	N/A	Section 8.1.1.2 Targets, pp. 324 to 333
	Non-Exempt Expulsion Fuse – Removal	GH-10	Remove non-exempt expulsion fuses/ cutouts from 3,000 fuse locations identified on distribution poles.	Remove non-exempt expulsion fuses/ cutouts from 3,000 fuse locations identified on distribution poles.	Remove non-exempt expulsion fuses/ cutouts from approximately 1,400 fuse locations (based on known population as of 1/26/23) identified on distribution poles.	Section 8.1.1.2 Targets, pp. 324 to 333

TABLE 7-3-2:
PG&E'S WMP TARGETS
(CONTINUED)

Category	Target Name	Initiative Activity Tracking ID	2023 Target & Unit	2024 Target & Unit	2025 Target & Unit	Location in WMP (Section)
	10K Undergrounding	GH-04	Complete 350 circuit miles of undergrounding work. The 350-circuit mile target includes: (1) undergrounding taking place as part of System Hardening, (2) undergrounding taking place as part of the Butte County Rebuild program (including a small volume of previously hardened overhead lines that are being placed underground) or other Community Rebuild programs, and (3) any other undergrounding work performed in HFTD, HFRA, Buffer Zone, or fire rebuild areas.	Complete 450 circuit miles of undergrounding work. The 450-circuit mile target includes: (1) undergrounding taking place as part of System Hardening, (2) undergrounding taking place as part of the Butte County Rebuild program (including a small volume of previously hardened overhead lines that are being placed underground) or other Community Rebuild programs, and (3) any other undergrounding work performed in HFTD, HFRA, Buffer Zone, or fire rebuild areas.	Complete 550 circuit miles of undergrounding work. The 550-circuit mile target includes: (1) undergrounding taking place as part of System Hardening, (2) undergrounding taking place as part of the Butte County Rebuild program (including a small volume of previously hardened overhead lines that are being placed underground) or other Community Rebuild programs, and (3) any other undergrounding work performed in HFTD, HFRA, Buffer Zone, or fire rebuild areas.	Section 8.1.1.2 Targets, pp. 324 to 333
	System Hardening – Transmission	GH-05	Remove or replace 43 circuit miles of transmission conductor on lines.	N/A	Remove or replace 5 circuit miles of transmission conductor.	Section 8.1.1.2 Targets, pp. 324 to 333
	System Hardening – Transmission Shunt Splices	GH-06	Install shunt splice(s) on 20 transmission lines.	Install shunt splice(s) on 22 transmission lines.	Install shunt splice(s) on 25 transmission lines.	Section 8.1.1.2 Targets, pp. 324 to 333
	Distribution Protective Devices	GH-07	Install and SCADA commission 75 new SCADA protective devices (Line Recloser, Fuse Saver, or Interrupter).	N/A	N/A	Section 8.1.1.2 Targets, pp. 324 to 333

TABLE 7-3-2:
PG&E'S WMP TARGETS
(CONTINUED)

Category	Target Name	Initiative Activity Tracking ID	2023 Target & Unit	2024 Target & Unit	2025 Target & Unit	Location in WMP (Section)
	Detailed Inspection Transmission – Ground	AI-02	Complete detailed ground inspections on 27,000 transmission structures in PG&E's asset registry as of January 1, 2023.	Complete detailed ground inspections on approximately 20,000 transmission structures in PG&E's asset registry as of January 1, 2024. Please note that this projected target may require modification based on changes in the risk output. The final inspection target units will be identified in PG&E's asset registry and updated in accordance with Section 12.3 of the 2023-2025 WMP Process and Evaluation Guidelines.	Complete detailed ground inspections on approximately 22,000 transmission structures in PG&E's asset registry as of January 1, 2025. Please note that this projected target may require modification based on changes in the risk output. The final inspection target units will be identified in PG&E's asset registry and updated in 2024 as part of the 2025 WMP Annual Update.	Section 8.1.1.2 Targets, pp. 324 to 333
	Detailed Inspection Transmission – Aerial	AI-04	Complete detailed aerial inspections on 24,000 transmission structures in PG&E's asset registry as of January 1, 2023.	Complete detailed aerial inspections on approximately 20,000 transmission structures in PG&E's asset registry as of January 1, 2024. Please note that this projected target may require modification based on changes in the risk output. The final inspection target units will be identified in PG&E's asset registry and updated in accordance with Section 12.3 of the 2023-2025 WMP Process and Evaluation Guidelines.	Complete detailed aerial inspections on approximately 19,000 transmission structures in PG&E's asset registry as of January 1, 2025. Please note that this projected target may require modification based on changes in the risk output. The final inspection target units will be identified in PG&E's asset registry and updated in 2024 as part of the 2025 WMP Annual Update.	Section 8.1.1.2 Targets, pp. 324 to 333

TABLE 7-3-2:
PG&E'S WMP TARGETS
(CONTINUED)

Category	Target Name	Initiative Activity Tracking ID	2023 Target & Unit	2024 Target & Unit	2025 Target & Unit	Location in WMP (Section)
	Detailed Inspection Transmission – Climbing	AI-05	Complete detailed climbing inspections of 1,700 transmission structures in PG&E's asset registry as of January 1, 2023.	Complete detailed climbing inspections on approximately 1,200 transmission structures in PG&E's asset registry as of January 1, 2024. Please note that this projected target may require modification based on changes in the risk output. The final inspection target units will be identified in PG&E's asset registry and updated in accordance with Section 12.3 of the 2023-2025 WMP Process and Evaluation Guidelines.	Complete detailed climbing inspections on approximately 1,200 transmission structures in PG&E's asset registry as of January 1, 2025. Please note that this projected target may require modification based on changes in the risk output. The final inspection target units will be identified in PG&E's asset registry and updated in 2024 as part of the 2025 WMP Annual Update.	Section 8.1.1.2 Targets, pp. 324 to 333
	Perform transmission IR inspections	AI-06	Infrared patrols will be performed on 4,000 circuit miles of energized transmission line.	Infrared patrols will be performed on 4,000 circuit miles of energized transmission line. Please note that this projected target may require modification based on changes in the risk output. The final inspection target units will be identified in PG&E's asset registry and updated in accordance with Section 12.3 of the 2023 -2025 WMP Process and Evaluation Guidelines.	Infrared patrols will be performed on 3,500 circuit miles of energized transmission line. Please note that this projected target may require modification based on changes in the risk output. The final inspection target units will be identified in PG&E's asset registry and updated in 2024 as part of the 2025 WMP Annual Update.	Section 8.1.1.2 Targets, pp. 324 to 333

TABLE 7-3-2:
PG&E'S WMP TARGETS
(CONTINUED)

Category	Target Name	Initiative Activity Tracking ID	2023 Target & Unit	2024 Target & Unit	2025 Target & Unit	Location in WMP (Section)
	Detailed Ground Inspections – Distribution	AI-07	Complete detailed ground inspections on 234,648 distribution poles, which were identified in PG&E's asset registry as of December 27, 2022. As part of the target number above, detailed ground inspections will be completed on a 42,470-pole subset of distribution poles in Severe, Extreme, or High plat maps by July 31, 2023, which were identified in PG&E's asset registry as of December 27, 2022. Similarly, detailed ground inspections will be completed on a 30,062-pole subset of distribution poles in Medium plat maps by September 30, 2023, which were identified in PG&E's asset registry as of December 27, 2022. Lastly, detailed ground inspections will be completed on a 162,116-pole subset of distribution poles in Low plat maps by December 31, 2023, which were identified in PG&E's asset registry as of December 27, 2022.	Complete detailed inspections on approximately 233,501 distribution poles, which will be identified in PG&E's asset registry as of December 27, 2022. Please note that this projected target may require modification based on changes in the risk output. The final inspection target units will be identified in PG&E's asset registry and updated in accordance with Section 12.3 of the 2023-2025 WMP Process and Evaluation Guidelines.	Complete detailed inspections on approximately 244,000 distribution poles, which will be identified in PG&E's asset registry as of December 27, 2022. Please note that this projected target may require modification based on changes in the risk output. The final inspection target units will be identified in PG&E's asset registry and updated in 2024 as part of the 2025 WMP Annual Update.	Section 8.1.1.2 Targets, pp. 324 to 333

TABLE 7-3-2:
PG&E'S WMP TARGETS
(CONTINUED)

Category	Target Name	Initiative Activity Tracking ID	2023 Target & Unit	2024 Target & Unit	2025 Target & Unit	Location in WMP (Section)
	Supplemental Inspections – Substation Distribution	AI-08	Complete supplemental inspections on 52 distribution substations. Co-located Hydroelectric substations and Transmission & Distribution substations are counted separately as two distinct units.	Complete supplemental inspections on 76 distribution substations. Co-located Hydroelectric substations and Transmission & Distribution substations are counted separately as two distinct units.	Complete supplemental inspections on 78 distribution substations. Co-located Hydroelectric substations and Transmission & Distribution substations are counted separately as two distinct units.	Section 8.1.1.2 Targets, pp. 324 to 333
	Supplemental Inspections – Substation Transmission	AI-09	Complete supplemental inspections on 34 transmission substations. Co-located Hydroelectric substations and Transmission & Distribution substations are counted separately as two distinct units.	Complete supplemental inspections on 36 transmission substations. Co-located Hydroelectric substations and Transmission & Distribution substations are counted separately as two distinct units.	Complete supplemental inspections on 41 transmission substations. Co-located Hydroelectric substations and Transmission & Distribution substations are counted separately as two distinct units.	Section 8.1.1.2 Targets, pp. 324 to 333
	Supplemental Inspections – Hydroelectric Substations and Powerhouses	AI-10	Complete supplemental inspections on 41 Hydroelectric Generation Substations and Powerhouses. Co-located Hydroelectric substations and Transmission & Distribution substations are counted separately as two distinct units.	Complete supplemental inspections on 46 Hydroelectric Generation Substations and Powerhouses. Co-located Hydroelectric substations and Transmission & Distribution substations are counted separately as two distinct units.	Complete supplemental inspections on 40 Hydroelectric Generation Substations and Powerhouses. Co-located Hydroelectric substations and Transmission & Distribution substations are counted separately as two distinct units.	Section 8.1.1.2 Targets, pp. 324 to 333
	HFTD/HFRA Open Tag Reduction – Transmission	GM-02	PG&E will eliminate the known 16,831 HFTD and HFRA transmission Ignition Risk tags (tags found prior to January 1, 2023, with required end dates in 2023 or earlier).	N/A	N/A	Section 8.1.1.2 Targets, pp. 324 to 333

TABLE 7-3-2:
PG&E'S WMP TARGETS
(CONTINUED)

Category	Target Name	Initiative Activity Tracking ID	2023 Target & Unit	2024 Target & Unit	2025 Target & Unit	Location in WMP (Section)
	HFTD/HFRA Open Tag Reduction – Distribution Backlog	GM-03	Reduce 48 percent of the wildfire risk associated with backlog* ignition risk tags from 151.1 (risk units as of January 1, 2023) by 72.5 (48%) risk units. *Backlog 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.	Reduce 68 percent of the wildfire risk associated with backlog* ignition risk tags from 151.1 (risk units as of January 1, 2023) by 102.7 (68%) risk units. *Backlog 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.	Reduce 77 percent of the wildfire risk associated with backlog* ignition risk tags from 151.1 (risk units as of January 1, 2023) by 116.3 (77%) risk units. *Backlog 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.	Section 8.1.1.2 Targets, pp. 324 to 333
	EPSS – Down Conductor Detection (DCD)	GM-06	Make capable for DCD 500 protective device controllers or relays. This count includes protection devices that due to repair status cannot receive the DCD settings, and circuit reconfiguration resulting in descoping of device.	Make capable for DCD 400 protective device controllers or relays. This count includes protection devices that due to repair status cannot receive the DCD settings, and circuit reconfiguration resulting in descoping of device.	Make capable for DCD 250 protective device controllers or relays. This count includes protection devices that due to repair status cannot receive the DCD settings, and circuit reconfiguration resulting in descoping of device.	Section 8.1.1.2 Targets, pp. 324 to 333
Vegetation Management and Inspection	LiDAR Data Collection – Transmission[(a)]	VM-01	Collect LiDAR data of the Transmission System (17,500 circuit miles). The Transmission System circuit miles include both HFTD / HFRA and non-HTFD Transmission circuit miles.	Collect LiDAR data of the Transmission System (17,500 circuit miles). The Transmission System circuit miles include both HFTD / HFRA and non-HTFD Transmission circuit miles.	Collect LiDAR data of the Transmission System (17,500 circuit miles). The Transmission System circuit miles include both HFTD / HFRA and non-HTFD Transmission circuit miles.	Section 8.2.1.2 Targets, pp. 499 to 506
	Pole Clearing Program	VM-02	Inspect, clear, and maintain, where clearing is necessary, 77,503 poles per Vegetation Control Standard TD-7112S.	2024 pole count to be adjusted by the ending pole population in the previous year (2023) poles per Vegetation Control Standard TD-7112S will be inspected, cleared, and maintained where clearing is necessary.	2025 pole count to be adjusted by the ending pole population in the previous year (2024) poles per Vegetation Control Standard TD-7112S will be inspected, cleared, and maintained where clearing is necessary.	Section 8.2.1.2 Targets, pp. 499 to 506

TABLE 7-3-2:
PG&E'S WMP TARGETS
(CONTINUED)

Category	Target Name	Initiative Activity Tracking ID	2023 Target & Unit	2024 Target & Unit	2025 Target & Unit	Location in WMP (Section)
	Tree removal	VM-04	Removal of 15,000 trees identified from the legacy EVM program.	Removal of 20,000 trees identified from the legacy EVM program.	Removal of 25,000 trees identified from the legacy EVM program.	Section 8.2.1.2 Targets, pp. 499 to 506
	Defensible Space Inspections – Distribution Substation[b]	VM-05	Complete defensible space inspections in alignment with the guidelines set forth in LAND 4001P-01 at 131 distribution substations. Co-located Hydroelectric substations and Transmission & Distribution substations are counted separately as two distinct units.	Complete defensible space inspections in alignment with the guidelines set forth in LAND 4001P-01 at 131 distribution substations. Co-located Hydroelectric substations and Transmission & Distribution substations are counted separately as two distinct units.	Complete defensible space inspections in alignment with the guidelines set forth in LAND 4001P-01 at 131 distribution substations. Co-located Hydroelectric substations and Transmission & Distribution substations are counted separately as two distinct units.	Section 8.2.1.2 Targets, pp. 499 to 506
	Defensible Space Inspections – Transmission Substation[b]	VM-06	Complete defensible space inspections in alignment with the guidelines set forth in LAND 4001P-01 at 55 transmission substations. Co-located Hydroelectric substations and Transmission & Distribution substations are counted separately as two distinct units.	Complete defensible space inspections in alignment with the guidelines set forth in LAND 4001P-01 at 55 transmission substations. Co-located Hydroelectric substations and Transmission & Distribution substations are counted separately as two distinct units.	Complete defensible space inspections in alignment with the guidelines set forth in LAND 4001P-01 at 55 transmission substations. Co-located Hydroelectric substations and Transmission & Distribution substations are counted separately as two distinct units.	Section 8.2.1.2 Targets, pp. 499 to 506
	Defensible Space Inspections – Hydroelectric Substations and Powerhouses	VM-07	Complete defensible space inspections in alignment with the guidelines set forth in LAND 5201P-01 at 61 Hydroelectric Generation Substations and Powerhouses. Co-located Hydroelectric substations and Transmission & Distribution substations are counted separately as two distinct units.	Complete defensible space inspections in alignment with the guidelines set forth in LAND 5201P-01 at 61 Hydroelectric Generation Substations and Powerhouses. Co-located Hydroelectric substations and Transmission & Distribution substations are counted separately as two distinct units.	Complete defensible space inspections in alignment with the guidelines set forth in LAND 5201P-01 at 61 Hydroelectric Generation Substations and Powerhouses. Co-located Hydroelectric substations and Transmission & Distribution substations are counted separately as two distinct units.	Section 8.2.1.2 Targets, pp. 499 to 506

TABLE 7-3-2:
PG&E'S WMP TARGETS
(CONTINUED)

Category	Target Name	Initiative Activity Tracking ID	2023 Target & Unit	2024 Target & Unit	2025 Target & Unit	Location in WMP (Section)
	Vegetation Management – Quality Verification	VM-08	Each of the 3 programs (Routine Distribution, Routine Transmission and Pole Clearing) must achieve a 95 percent quality verification audit results pass rate. The estimated number of samples for Quality Verification audits for the 3 programs (Routine Distribution, Routine Transmission and Pole Clearing) are based on quality control completed work in HFTD areas. Quality verification audit locations will be identified using a statistically valid approach with a 95 percent confidence level and 5 percent margin of error. The pass rate and associated number of quality verification audit locations are based on the actual work completed in the calendar year.	The scope for Quality Verification reviews is subject to change and will be decided based on learning's from prior years, aligned to business needs and risks.	The scope for Quality Verification reviews is subject to change and will be decided based on learning's from prior years, aligned to business needs and risks.	Section 8.2.1.2 Targets, pp. 499 to 506
Situational Awareness and Forecasting	Line Sensor – Installations	SA-02	Install Line Sensor devices on 40 circuits.	Install Line Sensor devices on 40 circuits.	Install Line Sensor devices on 40 circuits.	Section 8.3.1.2 Targets, pp. 499 to 506

TABLE 7-3-2:
PG&E'S WMP TARGETS
(CONTINUED)

Category	Target Name	Initiative Activity Tracking ID	2023 Target & Unit	2024 Target & Unit	2025 Target & Unit	Location in WMP (Section)
Emergency Preparedness	Annually review, and revise if appropriate, the Company Emergency Response Plan (CERP) and the two wildfire-related annexes (the Wildfire Annex and the PSPS Annex)	EP-06	3 documents (1 CERP and 2 wildfire-related annexes)	3 documents (1 CERP and 2 wildfire-related annexes)	3 documents (1 CERP and 2 wildfire-related annexes)	Section 8.4.1.2 Targets, pp. 629 to 631
Community Outreach and Engagement	Community Engagement – Surveys	CO-02	PG&E will complete two PSPS education and outreach surveys.	PG&E will complete two PSPS education and outreach surveys.	PG&E will complete two PSPS education and outreach surveys.	Section 8.5.1.2 Targets, pp. 722 to 726
PSPS	Provide 12,000 cumulative new or replacement portable batteries to PG&E customers at risk of PSPS or EPSS, focusing on but not limited to AFN, MBL, and self-identified vulnerable populations	PS-06	Provide 4,000 cumulative new or replacement portable batteries to PG&E customers	Provide 4,000 cumulative new or replacement portable batteries to PG&E customers	Provide 4,000 cumulative new or replacement portable batteries to PG&E customers	Section 9.1.4 Targets, pp. 760 to 762

TABLE 7-3-2:
PG&E'S WMP TARGETS
(CONTINUED)

Category	Target Name	Initiative Activity Tracking ID	2023 Target & Unit	2024 Target & Unit	2025 Target & Unit	Location in WMP (Section)
PSPS	Reduce PSPS impacts by ~55k customer events (3.4%) for 2023-2025 period by completing planned Wildfire mitigation projects including but not limited to MSO switch replacements and undergrounding.	PS-07	15,000 customer events based on Wildfire mitigation projects including but not limited to MSO replacements and Undergrounded miles planned for 2023	33,000 customer events based on Wildfire mitigation projects including but not limited to MSO replacements and Undergrounded miles planned for 2023-2024	55,000 customer events based on Wildfire mitigation projects including but not limited to MSO replacements and Undergrounded miles planned for 2023-2025	Section 9.1.5 Targets, pp. 763 to 765 ACI PG&E-22-35 pp. 972 to 974

(a) VM-01 LiDAR is flown in late summer and early fall in the prior year to enable ground inspection's next cycle to begin in November that then allows tree work to commence on January 1 of the following year.

(b) VM-05 and VM-06 Defensible Space inspections begin in late November to enable work mitigation to be completed before fire season begins in the following year.

7.2.2 Anticipated Risk Reduction

In this section, the electrical corporation must present the expected risk reduction for each mitigation and the schedule on which it plans to implement the mitigation initiatives.

The electrical corporation must provide:

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

7.2.2.1 Projected Overall Risk Reduction

In this section, the electrical corporation must provide a figure showing the overall utility risk in its service territory as a function of time, assuming the electrical corporation meets the planned timeline for implementing the mitigations. 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

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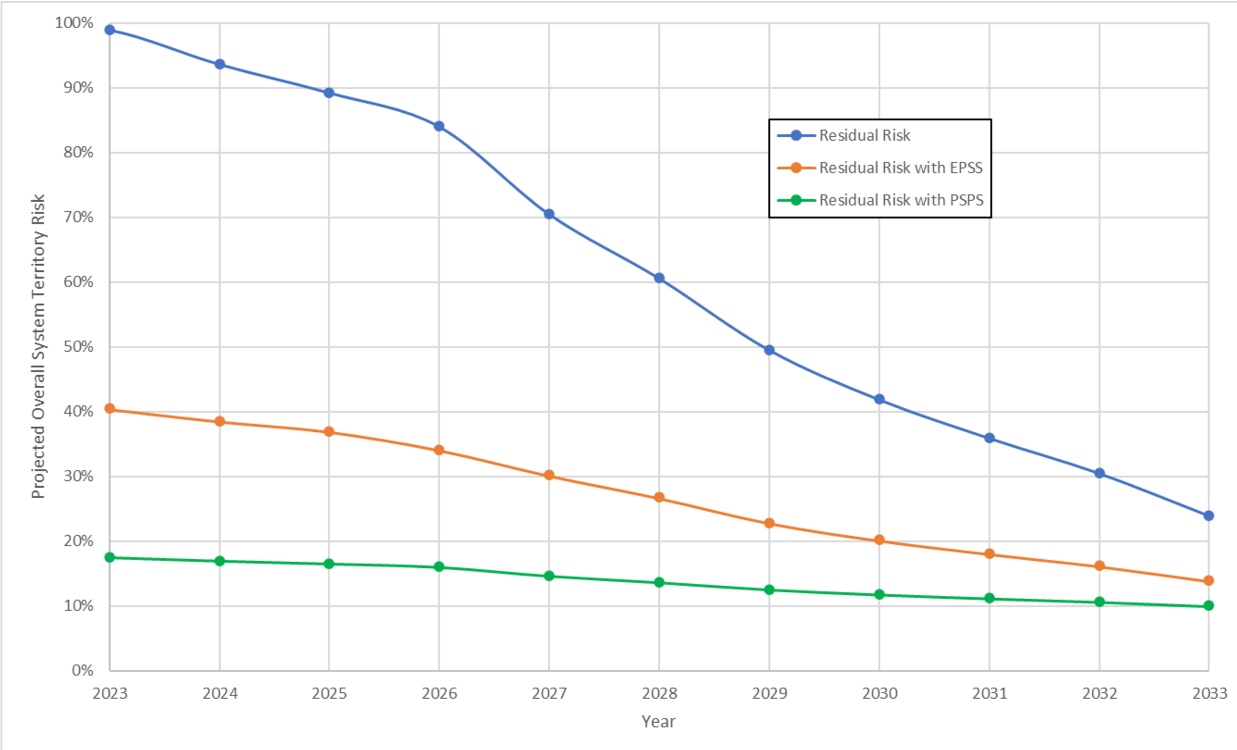
In this section PG&E describes our anticipated risk reduction resulting from our wildfire mitigation activities. We describe our projected overall risk reduction as a function of time for the next 10 years (Figure 7-1) and the projected risk reduction on our highest-risk circuits over the 3-year WMP cycle (Table 7-4).

This analysis represents the System Territory Risk reduction related to our portfolio of mitigations for the 3-year WMP cycle and only our undergrounding program for the remainder of the 10 years. The 10-year projection also includes the estimated risk reduction impacts from EPSS and PSPS.

Figure 7-1 shows PG&E's projected overall risk reduction for the next 10 years.

FIGURE 7-1:
PROJECTED OVERALL SYSTEM TERRITORY RISK



7.2.2.2 Risk Impact of Mitigation Initiatives

The electrical corporation must calculate the expected "x% risk impact" of each of its mitigation initiative activity targets for each year from 2023-2025. The expected x% risk impact is the expected percentage risk reduction on the last day of each year compared to the first day of that same year. For example:

For protective devices and sensitivity settings, the risk on Jan. 1, 2024 = 2.59×10^{-1}.

After meeting its planned initiative activity targets for protective devices and sensitivity settings, the risk on Jan. 1, 2024 = 1.29×10^{-1}.

The expected x% risk impact for the protective devices and sensitivity settings initiative in 2024 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 expected "x% risk impact" numbers must be reported for each planned mitigation initiative activities in the specific mitigation initiative sections of Section 8 (see example tables in Section 8).

To calculate percent Risk Impact, we start by calculating Overall Utility Risk which is the sum of Wildfire Risk + PSPS risk (as required by WMP Guidelines Figure 6-2).

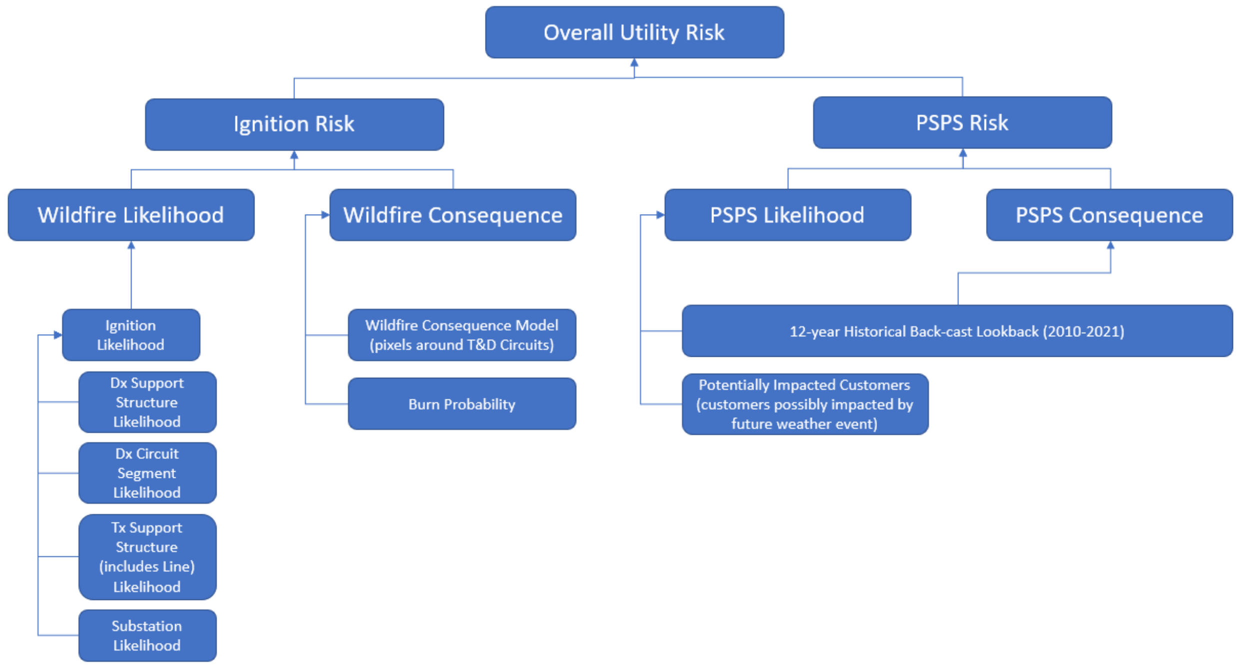
To calculate Overall Utility Risk we aggregate the risk scores from the Enterprise Risk Model (MAVF). Our Overall Utility Risk is:

$$\boldsymbol{Overall\ Utility\ Risk} \quad = Wildfire\ Risk\ (Dx,\ Tx,\ Sub) + PSPS\ Risk\ (Backcast,\ PIC)$$

$$\boldsymbol{Enterprise\ Risk}(\boldsymbol{MAVF}) = (23{,}082\ Dx + 772\ Tx + 14\ Sub) + (2170) = 26{,}038$$

We use information from our more granular risk models—WDRM, WTRM, and PSPS—that incorporate work prioritization and workplans. This information is calibrated at the overall level to compute an Overall Utility Risk calculation as shown in Figure PG&E-7.2.2-1B below.

FIGURE PG&E-7.2.2-1B:
PG&E'S OVERALL UTILITY RISK CALCUATION FRAMEWORK



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.

We use data from different risk models to inform these risk reduction calculations. The individual models used to support the calculations are listed in Table PG&E-7.2.2-1 below.

TABLE PG&E-7.2.2-1:
RISK MODEL USED TO CALCULATE RISK REDUCTION FOR INDIVIDUAL INITIATIVES

Initiative	Model Used
System Hardening – Distribution	WDRM (circuits segment)
System Hardening – Transmission	WTRM (structure + line)
Maintenance Backlog – Distribution (pole)	WDRM (support structure)
Maintenance Backlog – Distribution (non-pole)	WDRM (circuit segment)
Maintenance Backlog – Transmission	WTRM (structure + line)
Proactive Fuse Replacement	WDRM (circuit segment)
Proactive Surge Arrestor	WDRM (circuit segment)
WDRM (circuit segment) - DCD	WDRM (circuit segment)

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 the program provides overall to reducing wildfire risk. 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 and provide example calculations for each mitigation category. 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.

Comprehensive Monitoring and Data Collection

While inspections have historically been viewed as a control (controls do not reduce risk themselves but maintain the level of risk), PG&E exceeds the compliance requirements by inspecting assets more frequently. The way in which we quantify this risk reduction is considered “Eyes-on-Risk”. Eyes-on-Risk is calculated by aggregating the amount of risk on the structures or circuit segments being inspected divided by the total risk on the structures or circuit segments on the system. This helps prioritize our inspection program.

Table PG&E-7.2.2-2 is an example of the steps taken to calculate the risk reduction related to inspection programs.

TABLE PG&E-7.2.2-2:
EXAMPLE CALCULATION – EYES-ON-RISK RELATED TO INSPECTION PROGRAMS

Step	Operational Risk Value	Comments
Total Count	~700K	Total number of support structures in HFTD
Workplan Count	48K	Number of support structures in HFTD
% Exposure	7%	Percent of support structures inspected
Total Risk	23,082	Total Distribution Wildfire
Workplan Risk	6,883	Summation of Support Structure Risk Score in Workplan
% Eyes-on-Risk	30%	Percent of risk being inspected

Note: By inspecting 7 percent of structures in HFTD, PG&E has 30 percent eyes-on-risk.

Operational Mitigations

Operational mitigations like EPSS and DCD provide interim risk reduction if an emerging situation presents itself during the year. These programs provide tremendous in-year risk reduction, but their benefits are not sustained long-term unless we continually invest in them. Even though their benefits are not sustained long-term we can still calculate pre- and post-risk reduction.

Table PG&E-7.2.2-3 is an example of the steps taken to calculate risk reduction for Operational Mitigation programs.

TABLE PG&E-7.2.2-3:
EXAMPLE CALCULATION – OPERATIONAL MITIGATION

Step	Operational Risk Value	Comments
Total Overall Utility Risk	26,038	
Total Distribution Wildfire Risk	23,082	
Total Miles	~26K	HFTD Miles of Distribution Overhead
Workplan Miles	~11.7K	Number of expected HFTD miles deployed in 2023 workplan
% Exposure	45%	Workplan / total miles
Residual Risk after EPSS	7,155	Post-EPSS effectiveness
# of ignitions post EPSS	30	Number of Ignitions EPSS did not mitigate
# of ignitions initiative to detect potential failure mode	14	Number of Ignitions that are high impedance fault that initiative can detect
% of ignitions initiative to detect	14 / 30 = 47%	% of ignitions initiative detects
% of ignitions able to mitigate	25%	% of ignitions able to mitigate SME judgement
% Effectiveness	47% * 25% = 11.8%	% ignitions detected * % able to mitigate
Risk Reduction	7,155 * 45% * 11.8% = 380	Residual Risk * % Workplan Exposure * Effectiveness

Note: Risk reduction benefits of operational mitigations continue to exist if maintained in the subsequent years.

System Resilience Mitigations

The risk reduction due to large-scale infrastructure upgrades like system hardening overhead and underground is expected to have the most substantial and long-term system resilience benefits. These benefits scale beyond individual risk driver mitigations and span multiple drivers like equipment failure, vegetation, and animal contact.

Table PG&E-7.2.2-4 is an example of the steps taken to calculate the risk reduction related to system resilience programs like undergrounding.

TABLE PG&E-7.2.2-4:
EXAMPLE CALCULATION – SYSTEM RESILIENCE MITIGATION

Step	Operational Risk Value	Comments
Total Miles	~26K	HFTD Distribution Overhead Miles
Workplan Miles	683	Number of miles scoped for 2025, not accounting for operational constraints
Workplan Target	550	Miles expected to be complete
% Exposure	550 / 26K = ~2.1%	Workplan Target/total miles
Wildfire Risk Reduction		
Total WDRM Risk	2,022	Total Risk Score (uncalibrated) to measure workplan
Workplan WDRM Risk Exposure	125	Risk Score associated with the miles workplan is addressing
Workplan Target WDRM Risk Exposure	125 * 550 / 683 = 101	Risk Score adjusted to the expected miles complete.
% Risk Exposure	101 / 2,022 = 4.99%	Percent of Risk expected to be targeted
% Effectiveness	99%	Program Effectiveness applied against targeted risk exposure
Workplan Wildfire Risk Reduction	101 * 99% = 100	Risk Reduction based on program effectiveness
WDRM to Enterprise MAVF Calibration	23,082 / 2,022 = 11.41	Calibrating WDRM to Enterprise MAVF Distribution Wildfire Score
Workplan Risk Reduction	100 * 11.41 = 1,141	Calibrating Risk Reduction to Enterprise MAVF
PSPS Risk Reduction		
Total PSPS Risk	2,170	Total PSPS Risk Score
Total Distribution PSPS Risk	1,317	Total PSPS Risk Score attributed to Distribution scoping
Workplan PSPS Risk Exposure	68	Risk Score associated with the miles workplan is addressing
Workplan PSPS Risk Exposure	68 * 550 / 683 = 55	Risk Score adjusted to the expected miles complete
Workplan Distribution Risk Exposure	37	Risk Score associated with Distribution workplan target
% Effectiveness	~100%	Program Effectiveness applied against targeted risk exposure
Risk Reduction	37 * 100% = 37	Risk Reduction based on program effectiveness

TABLE PG&E-7.2.2-4:
EXAMPLE CALCULATION – SYSTEM RESILIENCE MITIGATION
(CONTINUED)

Step	Operational Risk Value	Comments
Overall Risk Reduction		
Total Overall Risk Reduction	1,141 + 37 = 1,178	Total Overall Risk Reduction
Total Overall Utility Risk Reduction %	1,178 / 26,038 = 4.5%	Total Overall Utility Risk Reduction %

Note: By Undergrounding ~2.1 percent of HFTD Miles, PG&E expects 4.5 percent Overall Utility Risk Reduction.

The risk reduction due to backlog maintenance and proactive equipment replacement is based on a sample set of assets/notifications. The amount of work relative to the risk reduced can be pre-determined.

Table PG&E-7.2.2-5 is an example of the steps taken to calculate the risk reduction related to equipment replacement and maintenance backlog programs.

TABLE PG&E-7.2.2-5:
EXAMPLE CALCULATION – RISK REDUCTION RELATED TO REPLACEMENT AND MAINTENANCE BACKLOG PROGRAMS

Step	Operational Risk Value	Comments
Total Overall Utility Risk	26,038	
Total Distribution Wildfire Risk	23,082	
Total Unit Count	114K	Number of non-pole open tags
Workplan Unit Count	24K	Number of expected units worked in 2023 workplan
% Exposure	24K / 114K = 21%	Workplan/total count
Total Unit Risk Score	101	Total risk score of open tags
Workplan Unit Risk Score	64	Workplan risk score of open tags
% Risk Exposure	64%	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 is detectable via inspection, creating a tag
Risk Reduction	2,121*64%*35%*90%*15% = 64	Associated Risk Reduction
WDRM to Enterprise MAVF Calibration	11.41	Calibrating WDRM to Enterprise MAVF Distribution Wildfire Score
Workplan Risk Reduction	64 * 11.41 = 730	Calibrating Risk Reduction to Enterprise MAVF
% Risk Reduction	730 / 26,038 = 2.8%	Risk Reduction/Total Utility Risk

Note: By addressing 21 percent of non-pole open tags, PG&E targets 64 percent of tag risk.

7.2.2.3 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, showing risk levels before and after the implementation of mitigation initiatives. This must include the same circuits, segments, or span IDs presented in Section 6.4.2. 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 initiatives 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 mitigation initiative.*
  - *Mitigation initiatives by implementation year: Mitigation initiatives the electrical corporation plans to apply to the circuit in each year of the WMP cycle.*

Table 7-4 is based on our workplans as of February 2023. The mitigation initiatives described below are not Objectives or Targets for quarterly or annual reporting purposes in connection with this Plan.

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 7-4 are ranked by mean wildfire risk and sorted by total risk.

TABLE 7-4:
SUMMARY OF RISK REDUCTION FOR TOP RISK CIRCUIT SEGMENTS

Circuit Segment ID	Wildfire Mean Risk Score	HFTD Miles	Total Overall Risk Score[(a)]	Jan 1, 2023 Overall Risk[(b)]	Jan. 1, 2023 – Dec. 31, 2023 Mitigation Initiatives	Jan. 1, 2024 Overall Risk	Jan. 1, 2024 – Dec. 31, 2024 Mitigation Initiatives	Jan. 1, 2025 Overall Risk	Jan. 1, 2025 – Dec. 31, 2025 Mitigation Initiatives[(c)]	Jan. 1, 2026 Overall Risk
INDIAN FLAT 1104CB	0.0393	13.80	118.47	41.46	EPSS Veg Mgmt. (Annual & Second Patrol) Aerial Inspection Ground Inspection Non-Pole Backlog	41.38	EPSS Veg Mgmt. (Annual & Second Patrol) Aerial Inspection Ground Inspection Non-Pole Backlog Pole Backlog	38.78	EPSS Veg Mgmt. (Annual & Second Patrol) Aerial Inspection Ground Inspection Non-Pole Backlog Pole Backlog Undergrounding in 2026	38.57
BONNIE NOOK 1101CB	0.0295	17.80	91.28	35.51	EPSS Veg Mgmt. (Annual & Second Patrol) Expulsion Fuse Replacement Aerial Inspection Ground Inspection Non-Pole Backlog Pole Backlog	33.99	EPSS Veg Mgmt. (Annual & Second Patrol) Aerial Inspection Ground Inspection Non-Pole Backlog Tree Removal Pole Backlog	33.61	EPSS Veg Mgmt. (Annual & Second Patrol) Undergrounding Aerial Inspection Ground Inspection Non-Pole Backlog Line Removal Pole Backlog	18.68
ALLEGHANY 1102CB	0.0240	18.91	88.61	32.68	EPSS Veg Mgmt. (Annual & Second Patrol) Surge Arrestor Replacement Aerial Inspection Non-Pole Backlog Line Removal Pole Backlog	30.64	EPSS Veg Mgmt. (Annual & Second Patrol) Aerial Inspection Ground Inspection Non-Pole Backlog Pole Backlog	30.26	EPSS Veg Mgmt. (Annual & Second Patrol) Undergrounding Aerial Inspection Ground Inspection Non-Pole Backlog Pole Backlog	22.09
OAK HURST 110310140	0.0288	18.76	88.41	31.42	EPSS Veg Mgmt. (Annual & Second Patrol) Aerial Inspection Ground Inspection Non-Pole Backlog Tree Removal DCD Line Sensors Pilot Pole Backlog	29.97	EPSS Veg Mgmt. (Annual & Second Patrol) Aerial Inspection Ground Inspection Non-Pole Backlog Pole Backlog	29.41	EPSS Veg Mgmt. (Annual & Second Patrol) Aerial Inspection Ground Inspection Non-Pole Backlog Pole Backlog	29.41
SILVERADO 2104515946	0.0254	19.06	85.60	33.12	EPSS Veg Mgmt. (Annual & Second Patrol) Non-Pole Backlog	32.59	EPSS Veg Mgmt. (Annual & Second Patrol) Aerial Inspection Ground Inspection Tree Removal	32.29	EPSS Veg Mgmt. (Annual & Second Patrol) Aerial Inspection Ground Inspection Undergrounding in 2026	32.29

TABLE 7-4:
SUMMARY OF RISK REDUCTION FOR TOP RISK CIRCUIT SEGMENTS
(CONTINUED)

Circuit Segment ID	Wildfire Mean Risk Score	HFTD Miles	Total Overall Risk Score[(a)]	Jan 1, 2023 Overall Risk[(b)]	Jan. 1, 2023 – Dec. 31, 2023 Mitigation Initiatives	Jan. 1, 2024 Overall Risk	Jan. 1, 2024 – Dec. 31, 2024 Mitigation Initiatives	Jan. 1, 2025 Overall Risk	Jan. 1, 2025 – Dec. 31, 2025 Mitigation Initiatives[(c)]	Jan. 1, 2026 Overall Risk
HIGHLANDS 1102628	0.0261	15.78	75.58	23.83	EPSS Veg Mgmt. (Annual & Second Patrol) Undergrounding Overhead Hardening Aerial Inspection Ground Inspection Non-Pole Backlog DCD Line Removal Pole Backlog	12.94	EPSS Veg Mgmt. (Annual & Second Patrol) Surge Arrestor Replacement Aerial Inspection Ground Inspection Non-Pole Backlog Line Removal Pole Backlog	< 1	EPSS Veg Mgmt. (Annual & Second Patrol) Aerial Inspection Ground Inspection Line Removal	< 1
UPPER LAKE 11011276	0.0250	12.29	67.22	23.53	EPSS Veg Mgmt. (Annual & Second Patrol) Undergrounding Overhead Hardening Ground Inspection Non-Pole Backlog Pole Backlog	14.41	EPSS Veg Mgmt. (Annual & Second Patrol) Surge Arrestor Replacement Aerial Inspection Non-Pole Backlog Tree Removal Pole Backlog	13.52	EPSS Veg Mgmt. (Annual & Second Patrol) Undergrounding Overhead Hardening Ground Inspection Non-Pole Backlog Pole Backlog	6.75
MIDDLETOWN 110148212	0.0352	9.83	58.82	15.17	EPSS Veg Mgmt. (Annual & Second Patrol) Aerial Inspection Undergrounding Overhead Hardening	11.65	EPSS Veg Mgmt. (Annual & Second Patrol) Ground Inspection Undergrounding Overhead Hardening Tree Removal Surge Arrestor Replacement	5.73	EPSS Veg Mgmt. (Annual & Second Patrol) Aerial Inspection Overhead Hardening	1.74
APPLE HILL 21026552	0.0258	13.02	57.11	20.87	EPSS Veg Mgmt. (Annual & Second Patrol) Aerial Inspection Ground Inspection Non-Pole Backlog DCD Pole Backlog	20.14	EPSS Veg Mgmt. (Annual & Second Patrol) Undergrounding Aerial Inspection Ground Inspection Non-Pole Backlog Tree Removal Pole Backlog	5.01	EPSS Veg Mgmt. (Annual & Second Patrol) Aerial Inspection Ground Inspection Non-Pole Backlog Pole Backlog	4.97
NOTRE DAME 11042028	0.0245	11.39	50.10	17.90	EPSS Veg Mgmt. (Annual & Second Patrol) Aerial Inspection Ground Inspection Non-Pole Backlog DCD	17.56	EPSS Veg Mgmt. (Annual & Second Patrol) Aerial Inspection Ground Inspection Non-Pole Backlog Pole Backlog	17.28	EPSS Veg Mgmt. (Annual & Second Patrol) Aerial Inspection Ground Inspection Non-Pole Backlog Pole Backlog Undergrounding in 2026	17.26

TABLE 7-4:
SUMMARY OF RISK REDUCTION FOR TOP RISK CIRCUIT SEGMENTS
(CONTINUED)

Circuit Segment ID	Wildfire Mean Risk Score	HFTD Miles	Total Overall Risk Score[(a)]	Jan 1, 2023 Overall Risk[(b)]	Jan. 1, 2023 – Dec. 31, 2023 Mitigation Initiatives	Jan. 1, 2024 Overall Risk	Jan. 1, 2024 – Dec. 31, 2024 Mitigation Initiatives	Jan. 1, 2025 Overall Risk	Jan. 1, 2025 – Dec. 31, 2025 Mitigation Initiatives[(c)]	Jan. 1, 2026 Overall Risk
CLAYTON 221296224	0.0341	10.18	47.28	16.85	EPSS Veg Mgmt. (Annual & Second Patrol) Undergrounding Expulsion Fuse Replacement Aerial Inspection Ground Inspection Non-Pole Backlog Line Sensor Pilot Pole Backlog	14.53	EPSS Veg Mgmt. (Annual & Second Patrol) Aerial Inspection Ground Inspection Non-Pole Backlog Pole Backlog	14.22	EPSS Veg Mgmt. (Annual & Second Patrol) Overhead Hardening Aerial Inspection Ground Inspection Tree Removal Pole Backlog Undergrounding in 2026	12.86
ANTLER 11011384	0.0387	10.34	46.88	16.70	EPSS Veg Mgmt. (Annual & Second Patrol) Ground Inspection Non-Pole Backlog DCD Line Sensor Pilot Pole Backlog	16.23	EPSS Veg Mgmt. (Annual & Second Patrol) Aerial Inspection Non-Pole Backlog	16.00	EPSS Veg Mgmt. (Annual & Second Patrol) Aerial Inspection Ground Inspection Undergrounding in 2026	16.00
MONTICELLO 1101654	0.0268	8.30	43.06	15.70	EPSS Veg Mgmt. (Annual & Second Patrol) Aerial Inspection Ground Inspection	15.70	EPSS Veg Mgmt. (Annual & Second Patrol) Aerial Inspection Ground Inspection Non-Pole Backlog DCD	15.54	EPSS Aerial Inspection Ground Inspection Non-Pole Backlog Pole Backlog	14.93
BALCH NO 1 1101105414	0.0313	7.47	42.19	14.78	EPSS Veg Mgmt. (Annual & Second Patrol) Aerial Inspection Ground Inspection Non-Pole Backlog DCD Pole Backlog	13.90	EPSS Veg Mgmt. (Annual & Second Patrol) Aerial Inspection Ground Inspection Pole Backlog	13.90	EPSS Veg Mgmt. (Annual & Second Patrol) Aerial Inspection Ground Inspection Pole Backlog	13.89
CURTIS 170356972	0.0250	8.42	41.10	14.49	EPSS Veg Mgmt. (Annual & Second Patrol) Aerial Inspection Ground Inspection Non-Pole Backlog	13.71	EPSS Veg Mgmt. (Annual & Second Patrol) Aerial Inspection Ground Inspection	13.71	EPSS Veg Mgmt. (Annual & Second Patrol) Aerial Inspection Ground Inspection Undergrounding in 2026	13.71
MONTICELLO 1101630	0.0396	4.94	41.08	14.96	EPSS Veg Mgmt. (Annual & Second Patrol) Expulsion Fuse Replacement Aerial Inspection Ground Inspection Non-Pole Backlog	14.36	EPSS Veg Mgmt. (Annual & Second Patrol) Aerial Inspection Ground Inspection Non-Pole Backlog DCD Pole Backlog	13.80	EPSS Veg Mgmt. (Annual & Second Patrol) Aerial Inspection Ground Inspection	13.80

TABLE 7-4:
SUMMARY OF RISK REDUCTION FOR TOP RISK CIRCUIT SEGMENTS
(CONTINUED)

Circuit Segment ID	Wildfire Mean Risk Score	HFTD Miles	Total Overall Risk Score[(a)]	Jan 1, 2023 Overall Risk[(b)]	Jan. 1, 2023 – Dec. 31, 2023 Mitigation Initiatives	Jan. 1, 2024 Overall Risk	Jan. 1, 2024 – Dec. 31, 2024 Mitigation Initiatives	Jan. 1, 2025 Overall Risk	Jan. 1, 2025 – Dec. 31, 2025 Mitigation Initiatives[(c)]	Jan. 1, 2026 Overall Risk
PINE GROVE 1101CB	0.0473	5.05	32.00	11.89	EPSS Veg Mgmt. (Annual & Second Patrol) Ground Inspection Non-Pole Backlog Pole Backlog	11.63	EPSS Veg Mgmt. (Annual & Second Patrol) Aerial Inspection Non-Pole Backlog Pole Backlog	11.25	EPSS Veg Mgmt. (Annual & Second Patrol) Aerial Inspection Ground Inspection Non-Pole Backlog Pole Backlog Undergrounding in 2026	11.21
BUCKS CREEK 1101CB	0.0292	4.81	28.51	9.98	EPSS Veg Mgmt. (Annual & Second Patrol) Undergrounding Overhead Hardening	5.43	EPSS Veg Mgmt. (Annual & Second Patrol)	5.43	EPSS Veg Mgmt. (Annual & Second Patrol)	5.43
SILVERADO 2104646776	0.0343	5.69	26.59	11.69	EPSS Veg Mgmt. (Annual & Second Patrol) Aerial Inspection Ground Inspection Non-Pole Backlog Pole Backlog	11.32	EPSS Veg Mgmt. (Annual & Second Patrol) Aerial Inspection Ground Inspection Non-Pole Backlog	11.27	EPSS Veg Mgmt. (Annual & Second Patrol) Aerial Inspection Ground Inspection Undergrounding in 2026	11.27
CALISTOGA 1102131531	0.0272	5.04	26.03	9.55	EPSS Veg Mgmt. (Annual & Second Patrol) Expulsion Fuse Replacement Non-Pole Backlog Pole Backlog Existing REFCL Circuit	9.02	EPSS Veg Mgmt. (Annual & Second Patrol) Aerial Inspection Ground Inspection	9.02	EPSS Veg Mgmt. (Annual & Second Patrol) Ground Inspection Non-Pole Backlog Tree Removal Pole Backlog	8.85
APPLE HILL 1104CB	0.0260	5.65	16.86	6.60	EPSS Veg Mgmt. (Annual & Second Patrol) Ground Inspection Non-Pole Backlog Line Sensor Pilot Pole Backlog	6.28	EPSS Veg Mgmt. (Annual & Second Patrol) Undergrounding Aerial Inspection Non-Pole Backlog Pole Backlog	2.39	EPSS Veg Mgmt. (Annual & Second Patrol) Ground Inspection Non-Pole Backlog	2.39
MIDDLETOWN 1101171414	0.0245	3.59	16.55	5.81	EPSS Veg Mgmt. (Annual & Second Patrol) Aerial Inspection Non-Pole Backlog DCD Pole Backlog	5.49	EPSS Veg Mgmt. (Annual & Second Patrol) Aerial Inspection Ground Inspection Non-Pole Backlog	5.48	EPSS Veg Mgmt. (Annual & Second Patrol) Aerial Inspection Ground Inspection Non-Pole Backlog Pole Backlog Undergrounding in 2026	5.47
ELECTRA 1102CB	0.0264	2.60	13.93	4.88	EPSS Veg Mgmt. (Annual & Second Patrol) Aerial Inspection Ground Inspection	4.88	EPSS Veg Mgmt. (Annual & Second Patrol) Aerial Inspection Ground Inspection Non-Pole Backlog	4.52	EPSS Aerial Inspection Ground Inspection Pole Backlog	4.52

TABLE 7-4:
SUMMARY OF RISK REDUCTION FOR TOP RISK CIRCUIT SEGMENTS
(CONTINUED)

Circuit Segment ID	Wildfire Mean Risk Score	HFTD Miles	Total Overall Risk Score[(a)]	Jan 1, 2023 Overall Risk[(b)]	Jan. 1, 2023 – Dec. 31, 2023 Mitigation Initiatives	Jan. 1, 2024 Overall Risk	Jan. 1, 2024 – Dec. 31, 2024 Mitigation Initiatives	Jan. 1, 2025 Overall Risk	Jan. 1, 2025 – Dec. 31, 2025 Mitigation Initiatives[(c)]	Jan. 1, 2026 Overall Risk
ORO FINO 1102CB	0.0317	2.73	12.60	4.56	EPSS Veg Mgmt. (Annual & Second Patrol) Aerial Inspection Non-Pole Backlog Pole Backlog	4.44	EPSS Veg Mgmt. (Annual & Second Patrol) Aerial Inspection Ground Inspection Non-Pole Backlog Pole Backlog	4.31	EPSS Veg Mgmt. (Annual & Second Patrol) Aerial Inspection Ground Inspection Undergrounding in 2026	4.31
FRENCH GULCH 1101CB	0.0250	2.71	12.22	4.50	EPSS Veg Mgmt. (Annual & Second Patrol) Aerial Inspection Ground Inspection Non-Pole Backlog Pole Backlog	4.20	EPSS Veg Mgmt. (Annual & Second Patrol) Aerial Inspection Ground Inspection	4.20	EPSS Veg Mgmt. (Annual & Second Patrol) Aerial Inspection Ground Inspection	4.20
PARADISE 1103283794	0.0278	2.55	12.12	4.52	EPSS Veg Mgmt. (Annual & Second Patrol)	4.52	EPSS Veg Mgmt. (Annual & Second Patrol) Aerial Inspection Undergrounding (Butte)	4.52	EPSS Veg Mgmt. (Annual & Second Patrol) Ground Inspection	4.52
PARADISE 11061212	0.0270	2.37	12.04	6.21	EPSS Veg Mgmt. (Annual & Second Patrol) Aerial Inspection	6.21	EPSS Veg Mgmt. (Annual & Second Patrol) Aerial Inspection Ground Inspection Undergrounding (Butte)	6.21	EPSS Veg Mgmt. (Annual & Second Patrol) Aerial Inspection Ground Inspection	6.21
CRESTA 1101103126	0.0240	0.87	4.95	1.76	EPSS Veg Mgmt. (Annual & Second Patrol) DCD Existing Overhead Hardened Circuit	1.76	EPSS Veg Mgmt. (Annual & Second Patrol) Ground Inspection Non-Pole Backlog	1.68	EPSS Veg Mgmt. (Annual & Second Patrol) Aerial Inspection	1.68
CRESTA 1101546650	0.0259	0.90	4.36	1.53	EPSS Veg Mgmt. (Annual & Second Patrol) DCD Existing Overhead Hardened Circuit	1.53	EPSS Veg Mgmt. (Annual & Second Patrol) Ground Inspection Non-Pole Backlog	1.43	EPSS Veg Mgmt. (Annual & Second Patrol) Aerial Inspection	1.43
MONTICELLO 1101CB	0.0305	0.54	3.06	1.07	EPSS Veg Mgmt. (Annual & Second Patrol) Aerial Inspection Non-Pole Backlog	1.03	EPSS Veg Mgmt. (Annual & Second Patrol) Ground Inspection Non-Pole Backlog Pole Backlog	1.00	EPSS Veg Mgmt. (Annual & Second Patrol) Aerial Inspection	1.00
TIGER CREEK 0201CB	0.0409	0.40	2.30	0.81	EPSS Veg Mgmt. (Annual & Second Patrol) Aerial Inspection	0.81	EPSS Veg Mgmt. (Annual & Second Patrol) Undergrounding Ground Inspection Pole Backlog	<0.1	EPSS Veg Mgmt. (Annual & Second Patrol) Aerial Inspection	<0.1

TABLE 7-4:
SUMMARY OF RISK REDUCTION FOR TOP RISK CIRCUIT SEGMENTS
(CONTINUED)

Circuit Segment ID	Wildfire Mean Risk Score	HFTD Miles	Total Overall Risk Score[(a)]	Jan 1, 2023 Overall Risk[(b)]	Jan. 1, 2023 – Dec. 31, 2023 Mitigation Initiatives	Jan. 1, 2024 Overall Risk	Jan. 1, 2024 – Dec. 31, 2024 Mitigation Initiatives	Jan. 1, 2025 Overall Risk	Jan. 1, 2025 – Dec. 31, 2025 Mitigation Initiatives[(c)]	Jan. 1, 2026 Overall Risk
INDIAN FLAT 11044440	0.0386	0.24	1.74	0.61	EPSS Veg Mgmt. (Annual & Second Patrol) Circuit Segment is Associated with INDIAN FLAT 1104CB	0.61	EPSS Veg Mgmt. (Annual & Second Patrol) Circuit Segment is Associated with INDIAN FLAT 1104CB	0.61	EPSS Veg Mgmt. (Annual & Second Patrol) Undergrounding in 2026 with INDIAN FLAT 1104CB	0.61
CALPINE 1144304	0.0684	0.05	1.71	0.61	Privately Owned Line	0.61	Privately Owned Line	0.61	Privately Owned Line	0.61
APPLE HILL 2102CB	0.0901	0.17	1.43	0.53	EPSS Veg Mgmt. (Annual & Second Patrol) Ground Inspection Non-Pole Backlog	0.51	EPSS Veg Mgmt. (Annual & Second Patrol) Aerial Inspection Undergrounding with APPLE HILL 210236878[(d)]	0.51	EPSS Veg Mgmt. (Annual & Second Patrol) Ground Inspection	0.51
MIDDLETOWN 1103CB	0.0270	0.05	1.09	0.38	EPSS Veg Mgmt. (Annual & Second Patrol) Aerial Inspection Undergrounding in 2022 with MIDDLETOWN 11018494, MIDDLETOWN 1103830	0.38	EPSS Veg Mgmt. (Annual & Second Patrol) Ground Inspection	0.38	EPSS Veg Mgmt. (Annual & Second Patrol) Aerial Inspection	0.38
PLACERVILLE 210658118	0.1047	0.11	0.90	0.32	EPSS Veg Mgmt. (Annual & Second Patrol) Ground Inspection	0.32	EPSS Veg Mgmt. (Annual & Second Patrol) Aerial Inspection Veg Mgmt. (Annual & Second Patrol) Undergrounding with PLACERVILLE 210611132	0.32	EPSS Veg Mgmt. (Annual & Second Patrol) Ground Inspection	0.32
BALCH NO 1 1101CB	0.0533	0.01	0.82	0.29	EPSS Veg Mgmt. (Annual & Second Patrol) Aerial Inspection Ground Inspection	0.29	EPSS Veg Mgmt. (Annual & Second Patrol) Aerial Inspection Ground Inspection	0.29	EPSS Veg Mgmt. (Annual & Second Patrol) Aerial Inspection Ground Inspection	0.29
ALLEGHANY 11021101/2	0.0661	0.01	0.34	0.12	EPSS Veg Mgmt. (Annual & Second Patrol)	0.12	EPSS Veg Mgmt. (Annual & Second Patrol) Ground Inspection	0.12	EPSS Veg Mgmt. (Annual & Second Patrol) Aerial Inspection Undergrounding with ALLEGHANY 1102CB	0.12
CALPINE 1144962	0.0244	0.04	0.21	0.07	Privately Owned Line	0.07	Privately Owned Line	0.07	Privately Owned Line	0.07
CAMP EVERS 2105BL 2101	0.0449	0.00	0.09	0.03	EPSS Veg Mgmt. (Annual & Second Patrol) Interconnected with BEN LOMOND 1104BL, BEN LOMOND 0401CB and BURNS 2101BL at substation	0.03	EPSS Veg Mgmt. (Annual & Second Patrol) Ground Inspection Interconnected with BEN LOMOND 1104BL, BEN LOMOND 0401CB and BURNS 2101BL at substation	0.03	EPSS Veg Mgmt. (Annual & Second Patrol) Aerial Inspection Interconnected with BEN LOMOND 1104BL, BEN LOMOND 0401CB and BURNS 2101BL at substation	0.03

TABLE 7-4:
SUMMARY OF RISK REDUCTION FOR TOP RISK CIRCUIT SEGMENTS
(CONTINUED)

Circuit Segment ID	Wildfire Mean Risk Score	HFTD Miles	Total Overall Risk Score[(a)]	Jan 1, 2023 Overall Risk[(b)]	Jan. 1, 2023 – Dec. 31, 2023 Mitigation Initiatives	Jan. 1, 2024 Overall Risk	Jan. 1, 2024 – Dec. 31, 2024 Mitigation Initiatives	Jan. 1, 2025 Overall Risk	Jan. 1, 2025 – Dec. 31, 2025 Mitigation Initiatives[(c)]	Jan. 1, 2026 Overall Risk
MARIPOSA 2101929360	0.0334	0.07	0.09	0.03	EPSS Veg Mgmt. (Annual & Second Patrol) Previously Overhead Hardened with MARIPOSA 2101241564	0.03	EPSS Veg Mgmt. (Annual & Second Patrol) Ground Inspection Previously Overhead Hardened with MARIPOSA 2101241564	0.03	EPSS Veg Mgmt. (Annual & Second Patrol) Aerial Inspection Previously Overhead Hardened with MARIPOSA 2101241564	0.03

Note: Circuit segments are selected from highest to lowest mean wildfire or ignition risk and sorted by total overall utility risk. Based on that ranking, PG&E identifies 41 circuit segments that fall within the top 5 percent of risk.

(a) Excludes the risk reduction associated with EPSS.

(b) Accounts for risk reduction associated with EPSS.

(c) Projected 2026 underground miles are listed for awareness only. They are not factored into the Jan. 1, 2026 Overall Risk value as risk reduction benefits do not occur until Jan. 1, 2027.

(d) Where undergrounding work is associated with a different circuit segment we do not calculate risk reduction for the "original" circuit segment. For example, APPLE HILL 2102CB undergrounding is associated with circuit segment APPLE HILL 210236878 and the risk reduction is calculated only for APPLE HILL 210236878.

7.2.3 Interim Mitigation Initiatives

As indicated in Section 7.1.4.3, for each mitigation that will require greater than one year to implement, the electrical corporation must assess the potential need for interim mitigation initiatives to reduce risk until the primary or permanent mitigation initiative is in place. If the electrical corporation determines that an interim mitigation initiative is necessary, it must also develop and implement that initiative, as appropriate.

The electrical corporation must provide a description of the following in this section of the WMP:

- *The electrical corporation's procedures for evaluating the need for interim risk reduction;*
- *The electrical corporation's procedures for determining which interim mitigation initiative(s) to implement;*
- *The electrical corporation's characterization of each interim risk management/reduction action and evaluation of its specific capabilities to reduce risks, including:*
  - *Potential consequences of risk event(s) addressed by the improvement/mitigation; and*
  - *Frequency of occurrence of the risk event(s) addressed by the improvement/mitigation.*

Each interim mitigation initiative planned by the electrical corporation for implementation on high-risk circuits must be listed as a mitigation initiative in Section 8. In addition, interim mitigation initiatives must be discussed in the relevant mitigation initiative sections of the WMP and included in the related target tables.

PG&E's wildfire mitigations are divided into three categories: Comprehensive Monitoring and Data collection; Operational Mitigations; and System Resilience. 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 control programs pending the implementation of System Resilience mitigations, we will look to implement an interim solution. We determine which interim mitigation to implement following the procedures described in Section 7.1.4 above.

Operational Mitigations are divided into four interim mitigation groups.

- Group 1: Targeted programs such as Life Extension Application for Transmission Line Assets that can be implemented quickly and provide short-term mitigation until line replacement activities are completed.

- Group 2: Inspections and maintenance programs where we exceed compliance requirements until permanent mitigations are deployed and/or we implement new technologies so that we no longer need to exceed compliance requirements.

- Group 3: Operational Mitigations such EPSS and PSPS that will be discontinued in those areas where permanent risk reduction through undergrounding will occur.

- Group 4: Community engagement events used to convey local wildfire safety information to our customers in anticipation of potential PSPS events or other events that may impact them.

Group 1: Targeted transmission line rebuild includes replacements of major components such as structures, conductors, and insulators and is considered a permanent mitigation. These projects are costly and complex (long lead-time material, construction clearances, permitting), and typically take several years to complete. To help address interim risks, shorter-term mitigations are used to address risks by strengthening and extending the life of the components. Below are examples of these mitigations.

- Shunt splice installation on top of an existing splice that have been identified as having a higher risk of failure. This installation eliminates the splice as a single point of failure, as a failure of the original splice would not result in down conductor.

- Conductor segment replacements targets 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 is to reduce risk for lines where the conductor segments are at higher risks, but the structures are in good condition and there is no additional electrical capacity need to increase the conductor size.

- Transmission tower coating targets structures in areas subject to atmospheric corrosion. This work enables corrosion protection of the steel from environmental exposure and physical abrasions.

- Transmission tower cathodic protection is used to control the corrosion and extends the life of the structure foundations.

- 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.

Group 2: The mitigations that provide interim risk reduction because we exceed compliance requirements include the following:

- Equipment Maintenance and Repair;

- Pole Clearing Program;

- UDS;

- Wood Management;

- Substation Defensible Space;
- Focused Tree Inspections;
- Transmission Integrated VM; and
- Emergency Response VM.

Group 3: Operational Mitigations that will eventually be discontinued or reduced in those areas where permanent risk reduction is deployed.

- Temporary Distribution Microgrids – Reduces customers impacted by PSPS events and supports community resilience during PSPS events.
- CMEP and MIP – Addresses PSPS mitigation and supports energy resilience for our customers and communities.
- Downed Conductor Detection – DCD eliminates a potential ignition source in the HFTD area until a more permanent mitigation is in place.
- Enhanced Powerline Safety Settings – EPSS reduces the time it takes for line protective devices to de-energize a powerline when a fault occurs. Reliance on EPSS will decrease as lines are relocated underground.
- VM for Operational Mitigations – Reduces outages and potential ignitions by mitigating potential fall-in trees. This program will become unnecessary in areas where undergrounding occurs.
- PSPS Event – PG&E continues to reduce the scope of PSPS events and customers experiencing PSPS-related outages through improved situational awareness and grid monitoring and operations.
- Partial Voltage Detection – Identifies a potential ignition source and continues to be useful even when there is near complete undergrounding with only small segments of overhead conductors remaining.
- SIPT – The work performed by the SIPT crews will decrease as we reduce the number of ignitions through our various mitigation programs.
- Partial Voltage Force Out – EPSS enable circuits, if PV detected, a forced out would be triggered operating the closest source side enabled device, and then we dispatch T-Men to assess the location for potential hazards.

The interim risk mitigation provided by these mitigation initiatives is summarized in Section 7.2.1 above and additional detail about each one is provided in Section 8 and Section 9. A reference to the specific section where the mitigation is described in also included in Section 7.2.1 above. Frequency of occurrence of the risk event is discussed in Section 6.2.

Group 4: Community engagement events used to convey local wildfire safety information to our customers. These interim mitigations reduce the impacts of wildfire or outage events.

- Community Engagement

PACIFIC GAS AND ELECTRIC COMPANY

2023-2025 WILDFIRE MITIGATION PLAN

SECTION 8

WILDFIRE MITIGATIONS

8. Wildfire Mitigation

8.1 Grid Design, Operations, and Maintenance

8.1.1 Overview

In this section, the electrical corporation must identify objectives for the next 3- and 10-year periods, targets, and performance metrics related to the following grid design, operations, and maintenance programmatic areas:

- *Grid design and system hardening;*
- *Asset inspections;*
- *Equipment maintenance, and repair;*
- *Asset management and inspection enterprise system(s);*
- *Quality Assurance (QA)/quality control (QC);*
- *Open work orders;*
- *Grid operations and procedures; and*
- *Workforce planning.*

8.1.1.1 Objectives

Each electrical corporation must summarize the objectives for its 3-year and 10-year plans for implementing and improving its grid design, operations, and maintenance.[118] *These summaries must include the following:*

- *Identification of which initiative(s) in the Wildfire Mitigation Plan (WMP) the electrical corporation is implementing to achieve the stated objective, including Utility Initiative Tracking IDs;*
- *Reference(s) to applicable codes, standards, and best practices/guidelines and an indication of whether the electrical corporation exceeds an applicable code, standard, or regulation;*
- *Method of verifying achievement of each objective;*
- *A target completion date; and*
- *Reference(s) to the WMP section(s) or appendix, including page numbers, where the details of the objective(s) are documented and substantiated.*

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[118] Annual information included in this section must align with the Quarterly Data Report (QDR) data.

This information must be provided in Table 8-1 for the 3-year plan and Table 8-2 for the 10-year plan. Examples of the minimum acceptable level of information are provided below.

- Table 8-1 and Table 8-2 Information Summary: In Table 8-1 and Table 8-2, we are providing the objective name (Objective Name), a description of the objective (Objective Description), the anticipated outlook of the objective (3-Year/10-Year Outlook), the planned due date for the objective (Completion Date), the applicable Initiative Tracking ID (Initiative Tracking ID), "Applicable Regulations, Codes, Standards, and Best Practices", "method of verification", and "section and page #" references. As noted in Section 7.2.1, "Applicable Regulations, Codes, Standards, and Best Practices", "method of verification", and "section and page #" columns are not a part of the objective. Instead, the controlling objective information is in the "Objective Description" and "Completion Date" columns.

- Reporting: Unless changed through Energy Safety's Change Order process, Pacific Gas and Electric Company (PG&E) will use the objectives in Table 8-1 and Table 8-2 below for quarterly compliance reporting including the QDR, Quarterly Notification (QN), and the Annual Report on Compliance (ARC). We note that throughout this 2023-2025 WMP, we discuss current plans for wildfire-related activities beyond the objectives in Table 8-1 and Table 8-2. The timing and scope of these additional activities and work may change. We will not be reporting on these plans or activities in our QDR, QN, or ARC because they are not objectives but are descriptions of plans and activities in our 2023-2025 WMP to provide a complete picture of our wildfire mitigation activities.

- External Factors: All objectives in the below Table 8-1 and Table 8-2 are subject to External Factors which represent reasonable circumstances which may impact execution against objectives including, but not limited to, physical conditions, landholder refusals, environmental delays, 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 ID: We are including Initiative Tracking IDs in each section that has associated targets and objectives. Table 8-1 and Table 8-2 display the Tracking IDs we are implementing to tie the objectives to the narratives and initiatives in the WMP. The Initiative Tracking IDs will also be used for reporting in the QDR.

TABLE 8-1:
GRID DESIGN, OPERATIONS, AND MAINTENANCE OBJECTIVES (3-YEAR PLAN)

Objective Name	Objective Description	Applicable Initiative(s), Tracking ID(s)	Applicable Regulations, Codes, Standards, and Best Practices (See Note)	Method of Verification (i.e., program)	Completion Date	Reference (Section and Page #)
Evaluate Covered Conductor Effectiveness	Update the covered conductor recorded effectiveness calculation using 2023 and 2024 outage data on the lines that have Covered Conductors for consideration in future system hardening workplans.	GH-02	GO95, GO165, ACI PG&E 22-11	Whitepaper showing the updated covered conductor effectiveness calculation using 2023 outage data. Whitepaper showing the updated covered conductor effectiveness calculation using 2024 outage data.	3/29/2024 (2023 data) 3/31/2025 (2024 data)	Section 8.1.2.1 Page 338
Evaluate and Implement Covered Conductor Effectiveness Impact on Inspections and Maintenance Standards	Evaluate the output of the Phase 1 and Phase 2 covered conductor effectiveness study to: (1) determine the impacts of the study on the maintenance and inspections standards for deployed covered conductor assets; and (2) update TD-2305M-JA02 (overhead inspections job aid), as needed.	GH-03	GO95, GO165, TD-2305M-JA02	Report outlining the impacts of the methodology and any proposed changes. Updated TD-2305M-JA02 document for inspections and maintenance to include references to covered conductor asset inspection and maintenance, as needed.	12/31/2023	Section 8.1.2.1 Page 338

TABLE 8-1:
GRID DESIGN, OPERATIONS, AND MAINTENANCE OBJECTIVES (3-YEAR PLAN)
(CONTINUED)

Objective Name	Objective Description	Applicable Initiative(s), Tracking ID(s)	Applicable Regulations, Codes, Standards, and Best Practices (See Note)	Method of Verification (i.e., program)	Completion Date	Reference (Section and Page #)
Retainment of Inspectors and Internal Workforce Development	Develop a plan to increase retention over time for trained and qualified inspectors. Develop a plan to focus on increasing and sustaining a consistent, year-over-year internal workforce that builds on existing experience and mentors new employees for asset inspections.	AI-01	N/A	Multiyear resource plans.	12/31/2025	Section 8.1.9.1 Page 478
Develop Distribution Aerial Inspections program	Evaluate the continued use of aerial inspections for distribution overhead equipment.	AI-03	N/A	Report summarizing the results of the 2023 Aerial Inspections.	12/31/2023	Section 8.1.3.2.7 Page 406
Filling Asset Inventory Data Gaps	Populate missing age data in the Asset Registry (using “Installation Date” data element as a proxy) to 90 percent weighted average across risk prioritized distribution and transmission equipment.	AI-11	TD-9212S – Asset Registry Standard	List of targeted distribution and transmission equipment types. Baseline and actual rate of completeness for the “Installation Date” data element for each targeted distribution and transmission equipment type.	12/31/2025	Section 8.1.5 Page 433

TABLE 8-1:
GRID DESIGN, OPERATIONS, AND MAINTENANCE OBJECTIVES (3-YEAR PLAN)
(CONTINUED)

Objective Name	Objective Description	Applicable Initiative(s), Tracking ID(s)	Applicable Regulations, Codes, Standards, and Best Practices (See Note)	Method of Verification (i.e., program)	Completion Date	Reference (Section and Page #)
Asset Inspections – Quality Assurance	Perform annually, year-round Transmission and Distribution system inspection quality assurance audits of "QC complete" locations in HFTD areas. Statistically valid methodology parameters, such as a confidence level of 95 percent and 5 percent margin of error, will be utilized.	GM-01	N/A	Final reports and field guides for all audits.	12/31/2023 12/31/2024 12/31/2025	Section 8.1.6.1 Page 441
HFTD/HFRA Open Tag Reduction – Backlog Elimination – 3 Year Plan	Eliminate the backlog* of distribution open non-pole ignition risk tags. *Backlog 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.	GM-04	N/A	Closed notifications.	12/31/2025	Section 8.1.7.2 Page 449
Updates on EPSS Reliability Study	Provide annually an updated Enhanced Powerline Safety Settings (EPSS) reliability impact study per Areas for Continued Improvement (ACI) PG&E-22-32	GM-07	D-16-01-008 and Revision Notice 22-12 from 2022 WMP	Annual EPSS Reliability Study	2/15/2024 for 2023 data 2/15/2025 for 2024 data 2/15/2026 for 2025 data	Section 8.1.8.1.1 Page 463

TABLE 8-2:
GRID DESIGN, OPERATIONS, AND MAINTENANCE OBJECTIVES (10-YEAR PLAN)

Objective Name	Objective Description	Applicable Initiative(s), Tracking ID(s)	Applicable Regulations, Codes, Standards, and Best Practices (See Note)	Method of Verification (i.e., Program)	Completion Date	Reference (Section and Page #)
HFTD/HFRA Open Tag Reduction – Backlog Elimination – 7-year Plan	Eliminate the backlog* of open distribution pole ignition risk tag. Backlog is defined as the open ignition EC notifications known as of January 5, 2023, and found prior to January 1, 2023, in HFTD/HFRA locations.	GM-05	N/A	Closed notifications	12/31/2029	Section 8.1.7.2 Page 449

8.1.1.2 Targets

Initiative targets are forward -looking quantifiable measurements of activities identified by each electrical corporation in its WMP. Electrical corporations will show progress toward completing targets in subsequent reports, including QDRs and WMP Updates.

The electrical corporation must list all targets it will use to track progress on its grid design, operations, and maintenance for the three years of the Base WMP. Energy Safety's Compliance Assurance Division and third parties must be able to track and audit each target. For each initiative target, the electrical corporation must provide the following:

- *Utility Initiative Tracking IDs.*
- *Projected Targets for each of the three years of the Base WMP and relevant units.*
- *Quarterly, rolling targets for 2023 and 2024 (inspections only).*
- *The expected "x% risk impact" for each of the three years of the Base WMP. The expected x% risk impact is the expected percentage risk reduction per year, as described in Section 7.2.2.2.*
- *Method of verifying target completion.*

The electrical corporation's targets must provide enough detail to effectively inform efforts to improve the performance of the electrical corporation's grid design, operations, and maintenance initiatives.

Table 8-3 and Table 8-4 below provide examples of the minimum acceptable level of information.

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1. Table 8-3 Information Summary: In Table 8-3, we are providing the target name (Target Name), the applicable Initiative Tracking ID (Initiative Tracking ID) and a description of the Target for each applicable year (2023 Target & Unit, 2024 Target & Unit, 2025 Target & Unit), the "% Risk Impact" for each respective year, and the method of verification. As noted in Section 7.2.1, the percent Risk Impact and method of verification columns are not a part of the Target. Instead, the controlling target information is in the "Target & Unit" columns for each respective year.

2. Table 8-4 Information Summary: Table 8-4 contains the Q2 and Q3 quarterly targets for 2023 and 2024 as well as the year end targets for 2023, 2024, and 2025 for inspections. Please note, the end of year targets in Table 8-4 are also represented in Table 8-3. For readability and efficiency, the annual targets in Table 8-3 include additional language to provide more context on the quantitative target values, as well as all other required information associated with targets (i.e., method of verification, percent Risk Impact). Therefore, if additional context is needed to better understand the quarterly target values in Table 8-4, please refer to

the 2023 Target & Unit, 2024 Target & Unit, 2025 Target & Unit columns in Table 8-3 that have the same associated target name (Target Name).

3. Utility Initiative Tracking ID: We are including Initiative Tracking IDs in each section that has associated targets and objectives. Table 8-3 and Table 8-4 display the Tracking IDs we are implementing to tie the targets to the narratives and initiatives in the WMP. The Initiative Tracking IDs will also be used for reporting in the QDR.

4. Reporting: Unless changed through Energy Safety's Change Order process, 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. It is also important to note that throughout this 2023-2025 WMP, we discuss current plans for wildfire-related activities in addition to the Targets in Table 8-3 and Table 8-4. The timing and scope of these additional activities and work may change. We will not be reporting on these plans or activities in our QDR, QN, or ARC because they are not Targets but are descriptions of plans and activities in our 2023-2025 WMP to provide a complete picture of our mitigation activities.

5. Percent Risk Impact: The percent Risk Impact provided in Table 8-3 is calculated based on the risk reduction of the mitigation initiative divided by total overall utility risk as defined in Section 6.4.2, Section 7.2.2.2, and Section 7.2.2.3. The percent Risk Impact provided is an estimate based on the best available workplans applied against the latest risk models as of time of this filing. Please note, 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 percent Risk Impact projections could change. Additionally, for inspection and line sensor related targets, since inspections in of themselves do not reduce risk, instead we provided an "Eyes-on-Risk" value to provide insights into the level of risk being assessed.

6. External Factors: All targets in the below Table 8-3 and Table 8-4 are subject to External Factors which represent reasonable circumstances which may impact execution against targets including, but not limited to, physical conditions, landholder refusals, environmental delays, 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.

7. High Fire Threat District (HFTD), High Fire Risk Area (HFRA), Buffer Areas: Unless stated otherwise, all initiative work described in Table 8-3 involves work or audits on units or equipment located in, traversing, energizing, or protecting units or equipment in HFTD, HFRA, or Buffer Zone areas.

TABLE 8-3:
GRID DESIGN, OPERATIONS, AND MAINTENANCE TARGETS BY YEAR

Target Name	Initiative Activity Tracking ID	Reference Section	2023 Target & Unit	x% Risk Impact 2023	2024 Target & Unit	x% Risk Impact 2024	2025 Target & Unit	x% Risk Impact 2025	Method of Verification
System Hardening – Distribution	GH-01	8.1.2.1	Complete 420 circuit miles of system hardening work which includes overhead system hardening, undergrounding, and removal of overhead lines in HFTD, HFRA, or buffer zone areas except for any mileage being undergrounded and tracked separately as part of our Butte County Rebuild and other Community Rebuild efforts.	2%	Complete 470 circuit miles of system hardening work which includes overhead system hardening, undergrounding, and removal of overhead lines in HFTD, HFRA, or buffer zone areas except for any mileage being undergrounded and tracked separately as part of our Butte County Rebuild and other Community Rebuild efforts.	4%	Complete 580 circuit miles of system hardening work which includes overhead system hardening, undergrounding, and removal of overhead lines in HFTD, HFRA, or buffer zone areas except for any mileage being undergrounded and tracked separately as part of our Butte County Rebuild and other Community Rebuild efforts.	5%	For post-construction projects, as-built job package and Fire Safe Spans Inspection report. For partially completed/ in-construction projects, design construction drawing and Fire Safe Spans Inspection report.
10K Undergrounding	GH-04	8.1.2.2	Complete 350 circuit miles of undergrounding work. The 350-circuit mile target includes: (1) undergrounding taking place as part of System Hardening, (2) undergrounding taking place as part of the Butte County Rebuild program (including a small volume of previously hardened overhead lines that are being placed underground) or other Community Rebuild programs, and (3) any other undergrounding work performed in HFTD, HFRA, Buffer Zone, or fire rebuild areas.	2%	Complete 450 circuit miles of undergrounding work. The 450-circuit mile target includes: (1) undergrounding taking place as part of System Hardening, (2) undergrounding taking place as part of the Butte County Rebuild program (including a small volume of previously hardened overhead lines that are being placed underground) or other Community Rebuild programs, and (3) any other undergrounding work performed in HFTD, HFRA, Buffer Zone, or fire rebuild areas.	3%	Complete 550 circuit miles of undergrounding work. The 550-circuit mile target includes: (1) undergrounding taking place as part of System Hardening, (2) undergrounding taking place as part of the Butte County Rebuild program (including a small volume of previously hardened overhead lines that are being placed underground) or other Community Rebuild programs, and (3) any other undergrounding work performed in HFTD, HFRA, Buffer Zone, or fire rebuild areas.	5%	For post-construction projects, as-built job package and Fire Safe Spans Inspection report. For partially completed/ in-construction projects, design construction drawing and Fire Safe Spans Inspection report.
System Hardening – Transmission	GH-05	8.1.2.5.1	Remove or replace 43 circuit miles of transmission conductor on lines.	<1%	N/A	N/A	Remove or replace 5 circuit miles of transmission conductor.	<1%	As-built job package.

TABLE 8-3:
GRID DESIGN, OPERATIONS, AND MAINTENANCE TARGETS BY YEAR
(CONTINUED)

Target Name	Initiative Activity Tracking ID	Reference Section	2023 Target & Unit	x% Risk Impact 2023	2024 Target & Unit	x% Risk Impact 2024	2025 Target & Unit	x% Risk Impact 2025	Method of Verification
System Hardening – Transmission Shunt Splices	GH-06	8.1.2.5.1	Install shunt splice(s) on 20 transmission lines.	<1%	Install shunt splice(s) on 22 transmission lines.	TBD	Install shunt splice(s) on 25 transmission lines.	TBD	As-built job package
Distribution Protective Devices	GH-07	8.1.2.8.1	Install and SCADA commission 75 new SCADA protective devices (Line Recloser, Fuse Saver, or Interrupter).	0%	N/A	0%	N/A	0%	As-built job package or SCADA Release Letters
Surge Arrestor – Removals	GH-08	8.1.2.10.4	Remove 663 non-exempt surge arrestors (based on the known population as of 01/12/2023) where known grounding issues exist. If no non-exempt surge arrestor is identified at a location during pre-field work, the unit will be resolved, and the notification will be canceled. Canceled notifications will count towards this target.	<1%	N/A	N/A	N/A	N/A	Closed work orders
Distribution Line Motor Switch Operator (MSO) – Replacements	GH-09	8.1.2.10.3	Replace or remove 20 MSOs (from the 47 identified as of January 26, 2023).	<1%	Replace or remove the remaining MSOs from the 47 identified, as of January 26, 2023.	<1%	N/A	N/A	As-built job package or (SCADA) Release Letters
Non-Exempt Expulsion Fuse – Removal	GH-10	8.1.2.10.5	Remove non-exempt expulsion fuses/ cutouts from 3,000 fuse locations identified on distribution poles.	<1%	Remove non-exempt expulsion fuses/ cutouts from 3,000 fuse locations identified on distribution poles.	<1%	Remove non-exempt expulsion fuses/ cutouts from approximately 1,400 fuse locations (based on known population as of 1/26/23) identified on distribution poles.	<1%	Closed work orders

TABLE 8-3:
GRID DESIGN, OPERATIONS, AND MAINTENANCE TARGETS BY YEAR
(CONTINUED)

Target Name	Initiative Activity Tracking ID	Reference Section	2023 Target & Unit	x% Risk Impact 2023	2024 Target & Unit	x% Risk Impact 2024	2025 Target & Unit	x% Risk Impact 2025	Method of Verification
Detailed Inspection Transmission – Ground	AI-02	8.1.3.1.1	Complete detailed ground inspections on 27,000 transmission structures in PG&E's asset registry as of January 1, 2023.	69% (Eyes-on -Risk)	Complete detailed ground inspections on approximately 20,000 transmission structures in PG&E's asset registry as of January 1, 2024. Please note that this projected target may require modification based on changes in the risk output. The final inspection target units will be identified in PG&E's asset registry and updated in accordance with Section 12.3 of the 2023-2025 WMP Process and Evaluation Guidelines.	TBD	Complete detailed ground inspections on approximately 22,000 transmission structures in PG&E's asset registry as of January 1, 2025. Please note that this projected target may require modification based on changes in the risk output. The final inspection target units will be identified in PG&E's asset registry and updated in 2024 as part of the 2025 WMP Annual Update.	TBD	Attainment report
Detailed Inspection Transmission – Aerial	AI-04	8.1.3.1.2	Complete detailed aerial inspections on 24,000 transmission structures in PG&E's asset registry as of January 1, 2023.	66% (Eyes-on -Risk)	Complete detailed aerial inspections on approximately 20,000 transmission structures in PG&E's asset registry as of January 1, 2024. Please note that this projected target may require modification based on changes in the risk output. The final inspection target units will be identified in PG&E's asset registry and updated in accordance with Section 12.3 of the 2023-2025 WMP Process and Evaluation Guidelines.	TBD	Complete detailed aerial inspections on approximately 19,000 transmission structures in PG&E's asset registry as of January 1, 2025. Please note that this projected target may require modification based on changes in the risk output. The final inspection target units will be identified in PG&E's asset registry and updated in 2024 as part of the 2025 WMP Annual Update.	TBD	Attainment report

TABLE 8-3:
GRID DESIGN, OPERATIONS, AND MAINTENANCE TARGETS BY YEAR
(CONTINUED)

Target Name	Initiative Activity Tracking ID	Reference Section	2023 Target & Unit	x% Risk Impact 2023	2024 Target & Unit	x% Risk Impact 2024	2025 Target & Unit	x% Risk Impact 2025	Method of Verification
Detailed Inspection Transmission – Climbing	AI-05	8.1.3.1.3	Complete detailed climbing inspections of 1,700 transmission structures in PG&E's asset registry as of January 1, 2023.	<1% (Eyes-on-Risk)	Complete detailed climbing inspections on approximately 1,200 transmission structures in PG&E's asset registry as of January 1, 2024. Please note that this projected target may require modification based on changes in the risk output. The final inspection target units will be identified in PG&E's asset registry and updated in accordance with Section 12.3 of the 2023-2025 WMP Process and Evaluation Guidelines.	TBD	Complete detailed climbing inspections on approximately 1,200 transmission structures in PG&E's asset registry as of January 1, 2025. Please note that this projected target may require modification based on changes in the risk output. The final inspection target units will be identified in PG&E's asset registry and updated in 2024 as part of the 2025 WMP Annual Update.	TBD	Attainment report
Perform transmission infrared (IR) inspections	AI-06	8.1.3.1.4	IR patrols will be performed on 4,000 circuit miles of energized transmission line.	56% (Eyes-on-Risk)	IR patrols will be performed on 4,000 circuit miles of energized transmission line. Please note that this projected target may require modification based on changes in the risk output. The final inspection target units will be identified in PG&E's asset registry and updated in accordance with Section 12.3 of the 2023-2025 WMP Process and Evaluation Guidelines.	TBD	IR patrols will be performed on 3,500 circuit miles of energized transmission line. Please note that this projected target may require modification based on changes in the risk output. The final inspection target units will be identified in PG&E's asset registry and updated in 2024 as part of the 2025 WMP Annual Update.	TBD	Attainment report

TABLE 8-3:
GRID DESIGN, OPERATIONS, AND MAINTENANCE TARGETS BY YEAR
(CONTINUED)

Target Name	Initiative Activity Tracking ID	Reference Section	2023 Target & Unit	x% Risk Impact 2023	2024 Target & Unit	x% Risk Impact 2024	2025 Target & Unit	x% Risk Impact 2025	Method of Verification
Detailed Ground Inspections – Distribution	AI-07	8.1.3.2.1	Complete detailed ground inspections on 234,648 distribution poles, which were identified in PG&E's asset registry as of December 27, 2022. As part of the target number above, detailed ground inspections will be completed on a 42,470-pole subset of distribution poles in Severe, Extreme, or High plat maps by July 31, 2023, which were identified in PG&E's asset registry as of December 27, 2022. Similarly, detailed ground inspections will be completed on a 30,062-pole subset of distribution poles in Medium plat maps by September 30, 2023, which were identified in PG&E's asset registry as of December 27, 2022. Lastly, detailed ground inspections will be completed on a 162,116-pole subset of distribution poles in Low plat maps by December 31, 2023, which were identified in PG&E's asset registry as of December 27, 2022.	40% (Eyes-on-Risk)	Complete detailed inspections on approximately 233,501 distribution poles, which will be identified in PG&E's asset registry as of December 27, 2022. Please note that this projected target may require modification based on changes in the risk output. The final inspection target units will be identified in PG&E's asset registry and updated in accordance with section 12.3 of the 2023-2025 WMP Process and Evaluation Guidelines.	47% (Eyes-on-Risk)	Complete detailed inspections on approximately 244,000 distribution poles, which will be identified in PG&E's asset registry as of December 27, 2022. Please note that this projected target may require modification based on changes in the risk output. The final inspection target units will be identified in PG&E's asset registry and updated in 2024 as part of the 2025 WMP Annual Update.	45% (Eyes-on-Risk)	Attainment report

TABLE 8-3:
GRID DESIGN, OPERATIONS, AND MAINTENANCE TARGETS BY YEAR
(CONTINUED)

Target Name	Initiative Activity Tracking ID	Reference Section	2023 Target & Unit	x% Risk Impact 2023	2024 Target & Unit	x% Risk Impact 2024	2025 Target & Unit	x% Risk Impact 2025	Method of Verification
Supplemental Inspections – Substation Distribution	AI-08	8.1.3.3.1	Complete supplemental inspections on 52 distribution substations. Co-located Hydroelectric substations and Transmission & Distribution substations are counted separately as two distinct units.	28% (Eyes-on -Risk)	Complete supplemental inspections on 76 distribution substations. Co-located Hydroelectric substations and Transmission & Distribution substations are counted separately as two distinct units.	TBD	Complete supplemental inspections on 78 distribution substations. Co-located Hydroelectric substations and Transmission & Distribution substations are counted separately as two distinct units.	TBD	Pronto report
Supplemental Inspections – Substation Transmission	AI-09	8.1.3.3.1	Complete supplemental inspections on 34 transmission substations. Co-located Hydroelectric substations and Transmission & Distribution substations are counted separately as two distinct units.	36% (Eyes-on Risk)	Complete supplemental inspections on 36 transmission substations. Co-located Hydroelectric substations and Transmission & Distribution substations are counted separately as two distinct units.	TBD	Complete supplemental inspections on 41 transmission substations. Co-located Hydroelectric substations and Transmission & Distribution substations are counted separately as two distinct units.	TBD	Pronto report
Supplemental Inspections – Hydroelectric Substations and Powerhouses	AI-10	8.1.3.3.1	Complete supplemental inspections on 41 Hydroelectric Generation Substations and Powerhouses. Co-located Hydroelectric substations and Transmission & Distribution substations are counted separately as two distinct units.	35% (Eyes-on -Risk)	Complete supplemental inspections on 46 Hydroelectric Generation Substations and Powerhouses. Co-located Hydroelectric substations and Transmission & Distribution substations are counted separately as two distinct units.	TBD	Complete supplemental inspections on 40 Hydroelectric Generation Substations and Powerhouses. Co-located Hydroelectric substations and Transmission & Distribution substations are counted separately as two distinct units.	TBD	Pronto report

TABLE 8-3:
GRID DESIGN, OPERATIONS, AND MAINTENANCE TARGETS BY YEAR
(CONTINUED)

Target Name	Initiative Activity Tracking ID	Reference Section	2023 Target & Unit	x% Risk Impact 2023	2024 Target & Unit	x% Risk Impact 2024	2025 Target & Unit	x% Risk Impact 2025	Method of Verification
HFTD/HFRA Open Tag Reduction – Transmission	GM-02	8.1.7.1	PG&E will eliminate the known 16,831 HFTD and HFRA transmission Ignition Risk tags (tags found prior to January 1, 2023, with required end dates in 2023 or earlier).	<1%	N/A	TBD	N/A	TBD	Closed work orders
HFTD/HFRA Open Tag Reduction – Distribution Backlog	GM-03	8.1.7.2	Reduce 48% of the wildfire risk associated with backlog* ignition risk tags from 151.1 (risk units as of January 1, 2023) by 72.5 (48%) risk units. *Backlog 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.	2.2% non-pole <1% pole	Reduce 68% of the wildfire risk associated with backlog* ignition risk tags from 151.1 (risk units as of January 1, 2023) by 102.7 (68%) risk units. *Backlog 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.	<1% non-pole <1% pole	Reduce 77% of the wildfire risk associated with backlog* ignition risk tags from 151.1 (risk units as of January 1, 2023) by 116.3 (77%) risk units. *Backlog 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.	<1% non-pole <1% pole	Closed work orders
EPSS – Down Conductor Detection (DCD)	GM-06	8.1.2.10.1	Make capable for DCD 500 protective device controllers or relays. This count includes protection devices that due to repair status cannot receive the DCD settings, and circuit reconfiguration resulting in descoping of device.	<2%	Make capable for DCD 400 protective device controllers or relays. This count includes protection devices that due to repair status cannot receive the DCD settings, and circuit reconfiguration resulting in descoping of device.	<1%	Make capable for DCD 250 protective device controllers or relays. This count includes protection devices that due to repair status cannot receive the DCD settings, and circuit reconfiguration resulting in descoping of device.	<1%	Report with the number of protective device controllers or relays that are DCD capable

TABLE 8-4:
ASSET INSPECTIONS TARGETS BY QUARTER

Target Name	Initiative Activity Tracking ID	Reference Section	Target End of Q2 2023 & Unit	Target End of Q3 2023 & Unit	End of Year Target 2023 & Unit	Target End of Q2 2024 & Unit	Target End of Q3 2024 & Unit	End of Year Target 2024 & Unit	End of Year Target 2025 & Unit
Detailed Inspection Transmission – Ground	AI-02	8.1.3.1.1	18,000 Transmission Structures	27,000 Transmission Structures	27,000 Transmission Structures	12,000 Transmission Structures	20,000 Transmission Structures	20,000 Transmission Structures	22,000 Transmission Structures
Detailed Inspection Transmission – Aerial	AI-04	8.1.3.1.2	17,000 Transmission Structures	24,000 Transmission Structures	24,000 Transmission Structures	17,000 Transmission Structures	20,000 Transmission Structures	20,000 Transmission Structures	19,000 Transmission Structures
Detailed Inspection Transmission – Climbing	AI-05	8.1.3.1.3	1,200 Transmission Structures	1,700 Transmission Structures	1,700 Transmission Structures	900 Transmission Structures	1,200 Transmission Structures	1,200 Transmission Structures	1,200 Transmission Structures
Perform transmission IR inspections	AI-06	8.1.3.1.4	1,500 Miles	3,000 Miles	4,000 Miles	1,500 Miles	3,000 Miles	4,000 Miles	3,500 Miles
Detailed Ground Inspections – Distribution	AI-07	8.1.3.2.1	123,699 Distribution Poles	193,699 Distribution Poles	234,648 Distribution Poles	190,805 Distribution Poles	233,501 Distribution Poles	233,501 Distribution Poles	244,000 Distribution Poles
Supplemental Inspections – Substation Distribution	AI-08	8.1.3.3.1	46 Distribution Substations	52 Distribution Substations	52 Distribution Substations	68 Distribution Substations	76 Distribution Substations	76 Distribution Substations	78 Distribution Substations
Supplemental Inspections – Substation Transmission	AI-09	8.1.3.3.1	31 Transmission Substations	34 Transmission Substations	34 Transmission Substations	33 Transmission Substations	36 Transmission Substations	36 Transmission Substations	41 Transmission Substations
Supplemental Inspections – Hydroelectric Substations and Powerhouses	AI-10	8.1.3.3.1	41 Hydroelectric Substations and Powerhouses	41 Hydroelectric Substations and Powerhouses	41 Hydroelectric Substations and Powerhouses	45 Hydroelectric Substations and Powerhouses	46 Hydroelectric Substations and Powerhouses	46 Hydroelectric Substations and Powerhouses	40 Hydroelectric Substations and Powerhouses

8.1.1.3 Performance Metrics Identified by the Electrical Corporation

Performance metrics indicate the extent to which an electrical corporation's WMP is driving performance outcomes. The electrical corporation must:

- *List the performance metrics the electrical corporation uses to evaluate the effectiveness of its grid design, operations, and maintenance in reducing wildfire and Public Safety Power Shutoff (PSPS) risk.*
- *For each of these performance metrics listed, the electrical corporation must:*
- *Report the electrical corporation's performance since 2020 (if previously collected);*
- *Project performance for 2023-2025; and*
- *List method of verification.*

The electrical corporation must ensure that each metric's name and values are the same in its WMP reporting as its QDR reporting (specifically, QDR Table 2 and QDR Table 3). Metrics listed in this section that are the same as performance metrics required by Energy Safety and reported in QDR Table 2 (Performance Metric) must match those reported in QDR Table 2. Metrics listed in this section that are not the same as any of the performance metrics identified by Energy Safety and reported in QDR Table 2 must match those reported in QDR Table 3.

The electrical corporation must:

- *Summarize its self-identified performance metrics in tabular form; and*
- *Provide a brief narrative that explains trends in the metrics.*

Table 8-5 provides an example of the minimum acceptable level of information.

Table 8-5 lists the recorded Grid Design, Operations, and Maintenance performance metrics by year, 2020-2022, and the projected metrics for 2023-2025.

Number of Risk events includes ignitions, wire downs, and outages in HFTD Tier 2 and Tier 3. The metric includes risk events on high wind warning days, red flag warning days, and no wind event days. The Number of Risk events is weather dependent. The projected number of Risk Events is based on a 5-year average that allows us to better account for yearly fluctuations.

PG&E tracks the number of distribution outages while EPSS is enabled. Recognizing that there is year-to-year variability in outage activity, we are taking steps to reduce the number of outages that occur while EPSS is enabled. PG&E launched EPSS as a pilot project in 2021 and in 2022 expanded the scope of EPSS to all HFRAs and select adjacent EPSS buffer zones. We are projecting a decrease in the number of outages by approximately 2 percent each year from 2023-2025 compared to the number of outages in 2022.

PG&E uses many performance metrics to evaluate the effectiveness of our PSPS Program. Some of these metrics include tracking the frequency, scope, and duration of PSPS events, as well as customer hours of PSPS per Red Flag Warning Overhead circuit mile days. We provide recorded data and an analysis of the past 5 years of weather data as a basis for the forecasted metrics.

Performance metrics related to frequency, scope, and duration of PSPS events are largely weather dependent and customer impact will fluctuate depending on the meteorological conditions and grid configuration at the time of each event.

Using our 2023 workplans for undergrounding and MSO replacements, PG&E projected PSPS metrics into 2023 and keeps those values static for 2024-2025. PG&E anticipates continued improvement from 2023-2025, but we do not yet have final workplans and analysis on the value of those improvements for the following years.

TABLE 8-5:
GRID DESIGN, OPERATIONS, AND MAINTENANCE PERFORMANCE METRICS RESULTS BY YEAR

Performance Metrics	2020	2021	2022	2023 Projected	2024 Projected	2025 Projected	Method of Verification (i.e., third-party evaluation, QDR)
Number of Risk events (ignitions, wire downs and outages in HFTD)	9,744	12,022	6,660	10,034	10,034	10,034	QDR[a]
Number of EPSS Events	[f]	[f]	2,375	2,350	2,300	2,250	QDR[b]
Frequency of PSPS Events	6	5	0	4	4	4	QDR[c]
Duration of PSPS Events (in customer hours)	22.3 million	2.5 million	0	12.3 million	12.2 million	12.0 million	QDR[d]
Total Number of Customers impacted by PSPS	649,685	80,319	0	317,151	313,527	309,138	QDR[e]

(a) QDR Table 2, QDR No. 1a – sum of HFTD Tier 2 and HFTD Tier 3.
(b) QDR Table 10, QDR No. 1d.
(c) QDR Table 10, QDR No. 1a.
(d) QDR Table 10, QDR No. 1c.
(e) QDR Table 10, QDR No. 4a.
(f) No data available as PG&E's EPSS program started only from 2022.

8.1.2 Grid Design and System Hardening

In this section, the electrical corporation must discuss how it is designing its system to reduce ignition 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.

The electrical corporation is required, at a minimum, to discuss grid design and system hardening for each of the following mitigation activities:

1. *Covered conductor installation;*
2. *Undergrounding of electric lines and/or equipment;*
3. *Distribution pole replacements and reinforcements;*
4. *Transmission pole/tower replacements and reinforcements;*
5. *Traditional overhead 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 PSPS events; and*
12. *Other technologies and systems not listed above.*

In Sections 8.1.2.1 *through* 8.1.2.12*, the electrical corporation must provide a narrative including the following information for each grid design and system hardening mitigation activity:*

Utility Initiative Tracking ID

<u>Overview of the Activity:</u> 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

Impact of the Activity on PSPS Risk

Updates to the Activity: Changes to the initiative since the last WMP submission and a brief explanation as to why those change were made. Discuss any planned improvements or updates to the activity and the timeline for implementation.

PG&E's Grid Design and System Hardening initiatives focus on mitigating wildfire risk in Tier 2 and 3 HFTD and HFRA areas within PG&E's service territory. Our System Hardening program focuses on mitigating potential catastrophic wildfire risk caused by transmission and distribution overhead assets. The mitigation portfolio also includes initiatives that mitigate or reduce the impact of wildfire related outages, including PSPS and EPSS.

Grid Design and System Hardening mitigations are risk informed. We discuss our risk analysis framework in Section 6 and our wildfire mitigation strategy in Section 7 of this WMP. We discuss our Grid Design and System Hardening initiatives in this section.

8.1.2.1 Covered Conductor Installation – Distribution

In Sections 8.1.2.1 *through* 8.1.2.12*, the electrical corporation must provide a narrative including the following information for each grid design and system hardening mitigation activity:*

Utility Initiative 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

Impact of the Activity on PSPS Risk

Updates to the Activity: Changes to the initiative since the last WMP submission and a brief explanation as to why those change were made. Discuss any planned improvements or updates to the activity and the timeline for implementation.

Office of Energy Infrastructure Safety (OEIS) Covered Conductor (CC) Installation Definition: Installation of covered or insulated conductors to replace standard bare or unprotected conductors (defined in accordance with General Order (GO) 95 as supply conductors, including but not limited to lead wires, not enclosed in a grounded metal pole or not covered by: a "suitable protective covering" (in accordance with Rule 22.8), grounded metal conduit, or grounded metal sheath or shield). In accordance with GO 95, conductor is defined as a material suitable for: (1) carrying electric current, usually in the form of a wire, cable or bus bar, or (2) transmitting light in the case of fiber optics; insulated conductors as those which are surrounded by an insulating material (in accordance with Rule 21.6), the dielectric strength of which is sufficient to withstand the maximum difference of potential at normal operating voltages of the circuit without breakdown or puncture; and suitable protective covering as a covering of wood or other non-conductive material having the electrical insulating efficiency (12 kilovolts (kV) per *inch dry) and impact strength (20ft.-lbs) of 1.5 inches of redwood or other material meeting the requirements of Rule 22.8-A, 22.8-B, 22.8-C or 22.8-D.*

Utility Initiative Tracking IDs: GH-01; GH-02; GH-03

Overview of the Activity

PG&E's System Hardening program, which includes targeted CC installation, focuses on mitigating potential catastrophic wildfire risk caused by distribution overhead assets. The System Hardening Program applies various mitigations to circuit segments that have the highest wildfire risk. For 2023, the highest wildfire risk miles are identified using the following categories:

1. Top Risk Based on Wildfire Distribution Risk Models (WDRM): The primary approach for selecting system hardening miles used two risk prioritization methodologies: (1) top 20 percent circuit segments based on the 2021 WDRM v2; and (2) the Wildfire Feasibility Efficiency (WFE)[119] ranked circuit segments based on the 2022 WDRM v3. Overhead hardening was selected where undergrounding was deemed infeasible for the WDRM v3 selection.

2. Fire Rebuilds: Rebuilding electric distribution lines within towns and communities in the aftermath of catastrophic wildfires. Overhead hardening Fire Rebuild work is identified through a decision tree to determine the type of rebuild (overhead hardening, undergrounding, or other solution) in areas that have been impacted by a wildfire and may include fire-impacted areas in both HFTD and non-HFTD; and

3. PG&E's Public Safety Specialist (PSS) Identified: Locations identified by PG&E's PSS team as presenting elevated wildfire risk.

CC installation involves the replacement of bare overhead primary conductor (voltage between 2-21 kV) 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, and by extension ignitions, due to line-to-line contacts, tree-branch contacts, and faults caused by animals. Installing CC on secondary lines has similar benefits as for primary lines.

Overhead system hardening, including CC installation, is effective in several environments including: (a) areas with low PSPS risk that have minimal tree fall-in risk with more short, grassy fuels; (b) areas with limited risk associated with entering and exiting (referred to as ingress and egress); or (c) in extreme terrain where undergrounding is not feasible. It can be effective against third-party impacts that cause line slap and some tree-fall situations, where there are fewer overstrike trees.

Overhead system hardening is an effective mitigation for many transient-type outages (brief power interruptions typically caused by temporary faults on power lines), as well

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[119] PG&E's WFE methodology is discussed in our response to ACI PG&E-22-34.

as those caused by contact from vegetation (i.e., eucalyptus bark, palm fronds, branches, etc.), birds, animals, and mylar balloons. Overhead system hardening also includes installing covered jumpers and animal protection in addition to the CC. This approach eliminates most exposed energized components and is effective in mitigating many phase-to-ground type outages. As such, overhead system hardening may be considered for HFTD or HFRA 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.

PG&E uses the same hardened overhead design criteria, including CC installation, when new or replacement overhead assets are installed as part of other planned work in the HFTD and HFRA, such as through projects driven by New Business, Work Requested by Others (WRO), or capacity and reliability upgrades, if installation or replacement of conductor is required.

Impact of the Activity on Wildfire Risk

PG&E uses the output from the WDRM to risk rank circuit segments. The circuit segment rankings are the first step in defining the highest risk circuit segments for project selection, planning, and execution.

Based on the latest analysis using data through 2022, the estimated effectiveness of mitigating ignition risk through CC is 64 percent. This is consistent with the previous results that were completed using data through 2020. We continue to review CC installation effectiveness associated with the System Hardening standard through the joint CC effectiveness study. Please refer to ACI PG&E-22-11 for more information about the latest preliminary effectiveness estimates based on the Joint IOU CC effectiveness study.

Impact of the Activity on PSPS Risk

Currently, PG&E does not consider CC as an exclusion criterion for PSPS events. Instead, PG&E uses other grid design and system hardening methods, such as undergrounding, to address PSPS risk.

Updates to the Activity

Since 2019, PG&E has installed approximately 960 miles of hardened overhead conductor, including approximately 335 overhead system hardening miles in 2022. For the period of this WMP, PG&E is significantly increasing the number of underground miles (see Section 8.1.2.2) and decreasing the number of overhead hardening miles relative to prior years.

PG&E's overall System Hardening program includes the combination of Overhead Hardening, Undergrounding (the System Hardening portion of Section 8.1.2.2) and Line Removal (Section 8.1.2.9). The estimated mileage contribution forecasts of the three sub-programs within System Hardening are found in Table PG&E-8.1.2-1 below (with non-System Hardening undergrounding as part of the Butte County Rebuild program included for reference as well).

TABLE PG&E-8.1.2-1:
OVERALL SYSTEM HARDENING MILEAGE FORECAST

Year	Estimated Overhead Covered Conductor Miles	Estimated System Hardening Undergrounding Miles	Estimated Line Removal Miles	Overall System Hardening Target	Estimated Butte County Rebuild Undergrounding Miles
2023	110	280	30	**420**	70
2024	75	380	15	**470**	70
2025	50	515	15	**580**	35
2026	50	750	15	**815**[(a)]	0
2023-2026	285	1,925	75	**2,285**	175

(a) The 2023 WMP requires annual targets for 2023-2025. The 2026 miles are provided as a forecast only.

As indicated above, and in Target GH-01, PG&E has set annual targets for overall system hardening work each year from 2023-2026. These targets are part of PG&E's larger plan to complete 2,285 miles of system hardening work from 2023-2026. The estimated mileage forecasts for each sub-type of hardening (overhead, underground and line removal) will vary from the actual mileage completed in each year. Additionally, if we complete system hardening miles above the annual targets in a particular year, we may lower future annual targets in a subsequent WMP or plan update, such that by the end of 2026 we have completed 2,285 miles of system hardening work.

8.1.2.2 Undergrounding of Electric Lines and/or Equipment – Distribution

In Sections 8.1.2.1 *through* 8.1.2.12*, the electrical corporation must provide a narrative including the following information for each grid design and system hardening mitigation activity:*

Utility Initiative Tracking ID

<u>Overview of the Activity:</u> 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

Impact of the Activity on PSPS Risk

<u>Updates to the Activity:</u> Changes to the initiative since the last WMP submission and a brief explanation as to why those changes were made. Discuss any planned improvements or updates to the activity and the timeline for implementation.

<u>OEIS Undergrounding of Electric Lines and/or Equipment Definition:</u> Actions taken to convert overhead electric lines and/or equipment to underground electric lines and/or equipment (i.e., located underground and in accordance with GO 128).

Utility Initiative Tracking ID: GH-04

Overview of the Activity

In July 2021, PG&E launched a multi-year program to underground 10,000 distribution circuit miles in high wildfire risk areas. Undergrounding will make our system safer and more resilient, allowing us to better serve our customers and address a rapidly changing climate. Additional benefits of undergrounding include improved reliability, reducing PSPS and EPSS outages, fewer emergency restoration activities during winter storms, and less need for vegetation management activities.

Undergrounding electric lines is part of PG&E's effort to minimize the growing wildfire risk in California. The primary risk addressed by undergrounding is reducing ignition potential from overhead electric distribution equipment and structures. By relocating existing overhead lines underground, ignition risk is reduced by approximately 99 percent. By the end of 2026, PG&E estimates that the undergrounding program will have effectively eliminated approximately 18 percent of the existing, quantified ignition risk in the HFTDs within PG&E's territory.

PG&E's undergrounding program is primarily delivered as part of the overall System Hardening program. Our system hardening program targets the highest wildfire risk miles, and it includes various mitigations such as line removal, conversion from overhead to underground, application of remote grid alternatives, mitigation of exposure through relocation of overhead facilities, and in-place overhead system hardening.

The 2023-2026 undergrounding portfolio is focused on undergrounding lines in the highest risk areas, which include the following:

1. Top Risk-Ranked Circuit Segments Based on WDRMs: The primary approach for selecting miles used two risk prioritization methodologies: (1) Top 20 percent circuit segments based on the 2021 WDRM v2; and (2) the WFE-ranked[120] circuit segments based on the 2022 WDRM v3 and considering undergrounding feasibility. Both approaches used to select undergrounding projects represent approximately 70 percent of our total wildfire risk.

2. Fire Rebuilds: Undergrounding electric distribution lines within towns and communities that are rebuilding in the aftermath of catastrophic wildfires. Undergrounding work in Fire Rebuild areas typically results from the use of a decision tree to determine the type of asset to rebuild and occurs in areas that have been impacted by an actual wildfire that may include fire-impacted areas in both HFTD and non-HFTD.[121]

3. PSPS Mitigation Projects: Projects identified that would reduce PSPS customer impacts.

4. PG&E's PSS Identification: Locations identified by PG&E's PSS team as presenting elevated wildfire risk such as ingress/egress constraints and community risk factors.

In addition to the undergrounding projects identified through the four avenues listed above, PG&E, at times, also undergrounds some previously overhead circuit segments in HFTDs through other programs, such as Rule 20, WRO, capacity, and reliability.

In executing the system hardening program, PG&E first uses a scoping criterion that identifies the highest risk areas, and then selects the appropriate risk mitigation approach for that circuit which may include undergrounding, remote grid installation, line removal, or overhead hardening (depending on the local circumstances). Since late 2021, PG&E has prioritized undergrounding as the preferred approach to reduce the most system risk. Once a circuit is selected for undergrounding, PG&E evaluates each proposed circuit segment quantitatively and qualitatively to mitigate the maximum amount of risk and evaluate feasibility and executability, to include the following factors:

- Existing infrastructure (i.e., water, natural gas, and sewer/stormwater drainage systems, bridges, streetlights, SCADA communications, number of services and transformers, community traffic and access impacts)

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120 PG&E's WFE methodology is discussed in our response to ACI PG&E-22-34, *supra*.

121 In the 2022 WMP, PG&E maintained a separate section for the Butte County Rebuild Program which focused on rebuilding specific Butte County assets underground. PG&E received feedback that this separation of one kind of undergrounding work was potentially confusing. For the 2023 WMP, PG&E has combined the Butte County Rebuild program within this section's electric distribution undergrounding program update to simplify the WMP by having all undergrounding activity discussed in one section.

- Major execution dependencies (i.e., land rights, environmental permitting, requirements for future road widening, paving plans, or moratoriums by local governments);
- Land and environment considerations (i.e., accessibility for ingress and egress of areas, waterway crossings, sensitive species habitats, land rights and easements, tribal lands, steep gradient, hard rock, tree density); and
- Community and Customer Considerations (i.e., cultural considerations, community, and customer impact).

Any of the above considerations may create delays or complexities that can impact the scope, cost, and schedule of undergrounding projects.

Undergrounding projects are executed in multiple stages once the circuit segment has been identified:

1. Scoping: Identifying the proposed route of undergrounding the electric distribution lines, which includes gathering base map data (i.e., Light Detection and Ranging (LiDAR) and survey data of the expected route) and identifying any long lead time dependencies (i.e., land acquisitions, environmental sensitivities and permits). Scoping includes breaking out planned circuit segments into smaller, more manageable projects. Scoping is the first step to providing visibility to the construction feasibility and possible execution timing.

2. Designing/Estimating: Designing the specific project to determine trench location, connection points, equipment details, materials needed, and related details, such as circuitry and pull boxes. The design also provides information about the land rights needed and produces the drawings that are submitted for permits. The project cost, including expected labor and materials, is calculated at this stage.

3. Dependencies: During this stage we may need to obtain land rights, environmental permits, construction contracts, encroachment permits from local counties, state and/or federal agencies, order long-lead materials, finalize construction cost estimates, and determine the construction schedule. The two longest lead dependencies often include obtaining land rights and environmental permits.

4. Construction: Executing the undergrounding takes place in two phases: (1) civil construction and (2) electric construction. Project schedules may be significantly impacted during civil construction due to unanticipated weather, discovery of hard rock, and/or detection of unmarked existing utility infrastructure. Once civil construction is complete with conduit and boxes installed, then electric construction resources pull the cable through the conduit, splice segments together and re-connect the customers to the new underground system. Customer input regarding the timing of re-connection, material availability, weather, and other risks can impact the electric construction schedule as well.

As projects move through each stage, schedule certainty improves. Project schedules can change at any time because of project dependencies which could cause projects to span multiple years. Generally, if a project is not completed during the year that it was originally targeted for completion, it will continue through all the job phases and be completed in a subsequent year.

PG&E works closely with customers, governments, agencies, tribes, and regulatory officials to manage these issues within the program and optimize project efficiency.

Impact of the Activity on Wildfire Risk

By replacing existing overhead lines with underground assets, ignition risk is reduced by approximately 99 percent in that area. PG&E is focusing on undergrounding in areas where it can be most beneficial in reducing wildfire risk and PSPS and EPSS outages that affect customers and critical facilities.

In December 2022, we updated our 2023-2026 undergrounding mileage[122] and have subsequently updated our workplan. As a result, based on the current 2023-2026 workplan, we are planning to perform approximately 87 percent of our undergrounding work on the top 20 percent of risk-ranked circuit segments, as identified by our risk models. With this updated workplan, PG&E's annual undergrounding portfolio increasingly addresses the top 20 percent risk-ranked circuit segments so that by 2025 95 percent of the portfolio addresses the top risk, and in 2026, almost 100 percent of the targeted annual undergrounding miles are focused on the top risk. Please refer to Table PG&E-8.1.2-3 below, which provides the details of the undergrounding mileage targets.

Impact of the Activity on PSPS Risk

PG&E is targeting certain undergrounding planning projects in areas most affected by PSPS. Beyond these targeted PSPS-reducing projects, whenever a line is undergrounded, PG&E may be able to mitigate PSPS activity in that area as the underground lines themselves do not pose an ignition risk during the extreme weather conditions that drive PSPS events. However, undergrounding does not always eliminate PSPS risk for the customers directly connected to the underground section, particularly when the undergrounded section remains connected to an overhead line either (upstream or downstream) in a HFRA that is subject to PSPS. As additional undergrounding is completed, and underground sections are connected, more PSPS risk will be mitigated.

Updates to the Activity

In 2022, PG&E completed approximately 180 miles of undergrounding compared to the target of 175 miles.

Of the undergrounding miles completed in 2022, approximately 60 of those miles were completed as part of the Butte County Rebuild Program that covers the Town of Paradise and lower Magalia. The planned underground work in the Butte County Rebuild started in 2019, and it is targeted for completion in 2025.

[122] A.21-06-021, PG&E's Reply Brief, (Dec. 9, 2022), p. 329, Table 4-2. See Appendix E.

In addition to the Butte County Rebuild, PG&E rebuilds in other communities affected by wildfires, including the community of Greenville in Plumas County, among others.

As shown in Table PG&E-8.1.2-2 below, and in Target GH-04, PG&E has current annual targets for undergrounding miles for each year from 2023-2026 (i.e., 350 miles for 2023, 450 miles for 2024 etc.). We adjusted the total planned mileage targets between 2023-2026 from approximately 3,300 to 2,100 miles as follows:

TABLE PG&E-8.1.2-2:
PG&E UNDERGROUNDING MILEAGE FORECAST

Year	Estimated System Hardening Undergrounding Miles	Estimated Butte County Rebuild Miles	Total Annual Underground Miles Target
2023	280	70	**350**
2024	380	70	**450**
2025	515	35	**550**
2026	750	0	**750**[a]
2023-2026	1,925	175	**2,100**

(a) The 2023 WMP requires annual targets for 2023-2025. The 2026 miles are provided as a forecast only.

The miles included in PG&E's workplan, as shown in Table PG&E-8.1.2-3 below, add up to more than the planned undergrounding of 2,100 total miles from 2023-2026. Note, the annual subtotals of system hardening vs. Butte County Rebuild underground miles are estimates only and may differ from the total miles completed each year.

Due to the multi-year nature of most undergrounding projects, PG&E may pull forward some miles within this four-year plan if it is feasible to do so. Ultimately, if additional projects can be executed earlier than outlined in these annual targets, then PG&E would seek to complete them earlier to eliminate the wildfire risk. If PG&E completes more miles than are included in an annual target in a particular year, then PG&E may lower future annual targets in a subsequent WMP or plan update so that by the end of 2026 we have undergrounded at least 2,100 miles in alignment with the multi-year plan and PG&E's General Rate Case.

The current multi-year plan is consistent with PG&E's commitment to implement our undergrounding proposal most efficiently and effectively. Among other benefits, the reduced pace (as compared to prior projections) will decrease costs in the initial years of the program. The target adjustment balances PG&E's planned work scope with meaningful risk reduction, as this plan will allow PG&E to target risk reduction in the highest wildfire risk areas to eliminate approximately 18 percent of existing wildfire risk by the end of 2026. PG&E remains fully committed to completing 10,000 miles of undergrounding in the highest wildfire risk areas.

In PG&E's Response to Critical Issue RN-PG&E-22-04 submitted in July 2022, we provided the miles included in the program and our plans to improve our risk modeling. PG&E has revisited the miles to be delivered through 2026 to ensure the continued focus on high-risk reduction. Further detail about the updates to the wildfire risk prioritization, including the WFE framework is described in ACI PG&E-22-34.

In addition, as described in ACI PG&E-22-16, PG&E's 2023-2026 Workplan encompasses projects totaling approximately 2,700 miles—exceeding PG&E's 2023-2026 target of 2,100 underground miles. Additional miles are intentionally built into the work plan to account for unforeseen delays to individual projects such as access, weather, permitting, land rights acquisition, materials, or other constraints. Thus, some of the projects included in this workplan may not be completed in the 2023-2026 timeframe. Generally, PG&E will continue working on these projects until they can be completed.

Finally, additional projects may be identified and added to the workplan going forward for potential completion between 2023-2026.

The following Table PG&E-8.1.2-3 includes a summary of all miles in our updated workplan as of January 3, 2023.

TABLE PG&E-8.1.2-3:
PG&E UNDERGROUNDING WORKPLAN 2023-2026

Portfolio Year		**2023**				**2024**				**2025**				**2026**				**2023-2026**			
# of Portfolio Miles		**534**				**588**				**683**				**881**				**2,687**			
Program Category		SH	Butte	Total Miles	% of Portfolio	SH	Butte	Total Miles	% of Portfolio	SH	Butte	Total Miles	% of Portfolio	SH	Butte	Total Miles	% of Portfolio	SH	Butte	Total Miles	% of Portfolio
Top 20 percent Risk-Ranked Circuit Segments		361	0	361	68%	458	0	458	78%	647	0	647	95%	879	0	879	100%	2,346	0	2,346	87%
Other High Risk	Fire Rebuild[(a)]	45	78	123	23%	6	99	105	18%	2	0	2	0%	1	0	1	0%	54	176	230	9%
	PSPS	47	0	47	9%	18	0	18	3%	16	0	16	2%	0	0	0	0%	81	0	81	3%
	PSS Identified	3	0	3	1%	1	0	1	0%	0	0	0	0%	0	0	0	0%	3	0	3	0%
	UG System Hardening	1	0	1	0%	1	0	1	0%	18	0	18	3%	0	0	0	0%	20	0	20	1%
Other UG Programs[(b)]		0	0	0	0%	5	0	5	1%	0	0	0	0%	0.4	0	0	0%	6	0	6	0%
Total		457	78	534	100%	489	99	588	100%	683	0	683	100%	881	0	881	100%	2510	176	2,687	100%

Note: The 2023 risk rank for segments is based on the 2021 WDRM v2. The 2024-2026 risk rank for segments is based on the 2022 WDRM v3. Numbers may vary due to rounding.

(a) Fire Rebuild miles are based on current, known rebuild needs. These miles may change due to future wildfire activity, which may affect other mileage goals in the 2022-2026 workplan.

(b) Other underground projects that are not in the top risk ranked circuits (e.g., Rule 20, WRO, Capacity).

At the portfolio level, PG&E continues to monitor and address risks that could impact the undergrounding program. Two of those risks are:

- Materials Availability and Supply Chain: The growth of the undergrounding program has and will put stress on our supply chain. To date, PG&E has been able to manage these challenges, including delays in padmount transformers (consistent with what others in the industry are experiencing), through planning ahead in partnership with our suppliers, shifting available materials to the most time-sensitive projects, and redesigning projects to accept substitute devices in some circumstances. For the near future, PG&E has identified enough supply to keep up with our needs, but we expect to incur constraints as the program continues to ramp up demands for key materials. These challenges could come in the form of complex materials, such as transformers, or simple materials, including underground elbows or concrete boxes needed to house underground equipment and joints.
- Workforce Demand: PG&E describes the workforce availability in Section 8.1.9.2. A subset of the workforce planning related to grid hardening is PG&E's undergrounding program. To meet the significant ramp up in mileage targets over the coming years, an undergrounding resource model has been developed and will continue to be refined. Given the specialized skills required to design and construct underground electric lines, we will continue to monitor our resource needs and availability.

8.1.2.3 Distribution Pole Replacements and Reinforcements

In Sections 8.1.2.1 *through* 8.1.2.12*, the electrical corporation must provide a narrative including the following information for each grid design and system hardening mitigation activity:*

Utility Initiative 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

Impact of the Activity on PSPS Risk

Updates to the Activity: Changes to the initiative since the last WMP submission and a brief explanation as to why those changes were made. Discuss any planned improvements or updates to the activity and the timeline for implementation.

OEIS Distribution Pole Replacements and Reinforcements Definition: Remediation, adjustments, or installations of new equipment to improve or replace existing distribution poles (i.e., those supporting lines under 65kV), including with equipment such as composite poles manufactured with materials reduce ignition probability by increasing pole lifespan and resilience against failure from object contact and other events.

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 found to be deficient, either by degradation, overload, or other means. Poles are identified for replacement through routine inspections, which include patrols, detailed visual inspections, and intrusive inspections. Poles are also identified for replacement 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.). Poles are identified for replacement 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). Poles are also identified for replacement when mechanically overloaded and a larger pole is required to support the conductor and overhead equipment.

Pole replacement includes providing more robust, up-to-standard designs for poles. These up-to-standard designs might include larger, stronger poles, or larger clearances. PG&E uses the WDRM v3 to prioritize distribution pole replacement workplans. Starting in 2023, we are bundling distribution pole replacements with non-pole maintenance tags to gain efficiencies and minimize customer impacts. The goal of bundling is to perform all the corrective maintenance (pole and non-pole) on the line segment under one clearance.

The distribution pole reinforcement program provides life extension for existing poles by installing a steel truss at the base of the wood poles. The truss supports the base of the wood pole, which strengthens it. Poles are tagged for reinforcement through the 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

Replacement or reinforcement of distribution poles can help reduce the occurrence of premature pole failures. Pole failures can result in energized wires on the ground, which could ignite a wildfire.

Impact of the Activity on PSPS Risk

Pole replacement and reinforcement reduce outage likelihood which decreases the chances of the area being impacted in future PSPS events. These programs also support public and employee safety because they improve the overall health of the distribution poles.

Updates to the Activity

In 2022, PG&E replaced more than 15,800 distribution poles and reinforced more than 780 distribution poles in HFTD/HFRA areas.

8.1.2.4 Transmission Pole/Tower Replacements and Reinforcements

In Sections 8.1.2.1 *through* 8.1.2.12*, the electrical corporation must provide a narrative including the following information for each grid design and system hardening mitigation activity:*

Utility Initiative Tracking ID

<u>Overview of the Activity:</u> 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

Impact of the Activity on PSPS Risk

<u>Updates to the Activity:</u> Changes to the initiative since the last WMP submission and a brief explanation as to why those change were made. Discuss any planned improvements or updates to the activity and the timeline for implementation.

<u>OEIS Transmission Pole/Tower Replacements and Reinforcements Definition:</u> Remediation, adjustments, or installations of new equipment to improve or replace existing transmission towers (e.g., structures such as lattice steel towers or tubular steel poles that support lines at or above 65 kV).

This initiative addresses remediation, adjustments, or installations of new equipment to improve or replace existing transmission 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.

Overview of the Activity

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 results in increased public and employee safety and customer reliability.

Transmission structure activities include the following:

- Transmission maintenance repair tags to mitigate a variety of deficiencies, such as bent or loose steel members, wood rot, foundation cracks, loose and/or worn hardware, etc. Mitigation of these tags in the HFTD can reduce wildfire risk. Further information and the related target for this activity are in Section 8.1.7.2.

- Transmission tower coating targets structures in areas subject to atmospheric corrosion. These structures are engineered with chemical compounds, such as corrosion inhibitors, which enable long term corrosion protection of the steel from UV exposure and physical abrasion.

- Transmission tower cathodic protection uses a technique to control the corrosion of a metal surface by making it the cathode of an electrochemical cell. A simple method of protection connects the metal to be protected to a more easily corroded sacrificial metal to act as the anode. The sacrificial metal then corrodes instead of the protected metal. For structures with large protection requirements, where passive galvanic cathodic protection is not adequate, an external Direct Current electrical power source is used to provide sufficient current.

- 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.

- 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. These current designs might include larger, stronger poles, or larger clearances. Most transmission wood poles are replaced with steel, most commonly light duty steel poles. These steel structures are less likely to ignite compared to wood poles and crossarms. Steel is also resistant to damage from woodpeckers, insects, and rot, threats which may degrade and reduce the strength of wood poles. Additionally, steel structures may be more difficult for animals to climb, reducing the risk of electrical contact to overhead conductors and ignition.

Impact of the Activity on Wildfire Risk

Transmission structure replacements and reinforcements reduce wildfire risk by decreasing the likelihood of asset failure. Specifically, for wood poles replaced with steel, ignition likelihood of energized components in contact with the structure or the ground is reduced.

Impact of the Activity on PSPS Risk

Reduced wildfire risk reduces PSPS risk, since asset probability of failure is a factor in scope determination, in addition to other factors. Replaced, healthier assets may be less likely to be in PSPS scope. Please refer to Section 9.2.1 for more information on the transmission line scoping procedure.

Updates to the Activity

In 2022, in addition to reinforcement work, over 3,200 structures were replaced (the majority being wood poles replaced with steel). Going forward, similar levels of wood to steel replacement is expected (in the thousands of poles) and is included as part of the larger maintenance Target GM-02 in Section 8.1.1.2.

8.1.2.5 Traditional Overhead Hardening –Transmission Conductor and Distribution

In Sections 8.1.2.1 *through* 8.1.2.12*, the electrical corporation must provide a narrative including the following information for each grid design and system hardening mitigation activity:*

Utility Initiative 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

Impact of the Activity on PSPS Risk

Updates to the Activity: Changes to the initiative since the last WMP submission and a brief explanation as to why those change were made. Discuss any planned improvements or updates to the activity and the timeline for implementation.

Updated OIES Traditional Overhead Hardening Definition: Maintenance, repair, and replacement of capacitors, circuit breakers, cross-arms, transformers, fuses, and connectors (e.g., hot line clamps) with the intention of minimizing the risk of ignition.

8.1.2.5.1 Traditional Overhead Hardening – Transmission Conductor

Utility Initiative Tracking ID: GH-05; GH-06

Overview of the Activity

PG&E does not have a separate program for overhead system component hardening that specifically aligns with the updated Energy Safety definition of traditional overhead hardening. See Section 8.1.4 for more information on PG&E's Asset Replacement and Maintenance programs. Projects that are discussed in this section focus on the risk associated with transmission line conductor failure, which may lead to wildfire ignition. There are two levels of projects for transmission conductor hardening, larger projects in the Targeted Line Rebuilt program and smaller projects in the Dispersed Conductor Component (Splice) Hardening and Conductor Segment Replacements.

Targeted Line Rebuild

Targeted lines traversing the HFTD were selected for conductor replacement. These lines are fully assessed for all component asset health, compliance against current standards, as well as electrical capacity needs. The project scope typically includes replacements of conductors, insulators, and structures. Asset replacements would restore assets to new, up-to-standard, and typically more robust design. These are large scale investments and work execution takes multiple years with involved permitting, construction and clearance planning. Some of these projects started a few years ago, but the units are only counted when a project is released to operations. For these reasons, the number of miles completed may vary significantly from year to year. This work is captured as part of Target GH-05 in Section 8.1.1.2. The target count is relatively low as several projects are in progress but will not be completed within the next couple of years.

Dispersed Conductor Component (Splice) Hardening

A conductor splice is a point of failure within a conductor span, due to factors such as corrosion, moisture intrusion, vibration, and workmanship variability. Certain types of splices, such as a twist splice, can have higher risk of failure compared to other splice types. A program has been initiated to install a shunt splice on top of the existing splice. This installation eliminates the splice as a single point of failure, as a failure of the original splice would not result in down conductor. Lines prioritized for this program are based on higher risk splice and wildfire consequence. Shunt splice installation is part of Target GH-06 in Section 8.1.1.2.

Conductor Segment Replacements

Another program has been initiated to replace targeted conductor segments within a line. A transmission line may consist of multiple conductor types, including spans of higher-risk segments such as small-sized conductors. This program reduces risk for lines 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 Wildfire Transmission Risk Model (WTRM). This program is in the planning phase and will not have work completed until after 2025.

Impact of the Activity on Wildfire Risk

Replacement or reinforcement of conductor in the HFTD reduces wildfire risk by decreasing the likelihood of asset failure.

Impact of the Activity on PSPS Risk

Generally, lines that have been hardened against conductor failure via replacement are less likely to be included in the scoping of future PSPS events. Asset health is a key factor in the decision to include a transmission line in PSPS scope along with other factors described in Section 9.2.1. A new conductor should have a lower probability of asset failure.

Updates to the Activity

Targeted Line Rebuild Projects

In the Targeted Line Rebuild program, projects were initiated before WTRM was available and were based on HFTD region and other factors including compliance. These projects are in progress and deemed beneficial to continue to completion. PG&E had conducted a risk, scope, and execution-stage assessment in 2022 for the projects in progress to determine if the project should proceed or if it is feasible to put on hold.

This effort allows a quicker transition to use the current risk model to drive future projects.

As described above, PG&E has initiated two new programs – Dispersed Conductor Component (Splice) Hardening and Conductor Segment Replacements. These programs are based on WTRM and other asset health and performance risk considerations.

8.1.2.5.2 Traditional Overhead Hardening – Distribution

PG&E does not have a separate program for overhead system component hardening that aligns with the updated OEIS definition of traditional overhead hardening.

See Section 8.1.4 for more information on PG&E's Asset Replacement and Maintenance programs.

8.1.2.6 Emerging Grid Hardening Technology Installations and Pilots

In Sections 8.1.2.1 *through* 8.1.2.12*, the electrical corporation must provide a narrative including the following information for each grid design and system hardening mitigation activity:*

Utility Initiative 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

Impact of the Activity on PSPS Risk

Updates to the Activity: Changes to the initiative since the last WMP submission and a brief explanation as to why those change were made. Discuss any planned improvements or updates to the activity and the timeline for implementation.

OEIS Emerging Grid Hardening Technology Installations and Pilots Definition: Development, deployment, and piloting of novel grid hardening technology.

Overview of the Activities

As discussed below, PG&E is working on developing, deploying, and piloting of novel grid hardening technology including Distribution, Transmission, and Substation: Fire Action Schemes and Technology (DTS-FAST) and Breakaway connector. In addition, the Electric Program Investment Charge (EPIC) 3.15, Proactive Wires Down Mitigation Demonstration Project (Rapid Earth Fault Current Limiter) is described in detail in Section 8.1.8.1.3.1. The impact and update questions from this section are answered there.

8.1.2.6.1 Distribution, Transmission, and Substation: Fire Action Schemes and Technology

Overview of the Activity

DTS-FAST is a technology developed internally at PG&E. It uses fraction of a second technologies to detect an object (such as a falling branch) approaching an energized power line and responds quickly to shut off power before the object impacts the line. In addition, DTS-FAST may detect elevated fire risk conditions associated with energized power lines, quickly shutting off power when such risks occur, including downed power lines, downed and leaning towers and poles, and equipment failures.

Impact of the Activity on Wildfire Risk

If deployed, DTS-FAST could have a significant impact on wildfire risk where deployed.

Impact of the Activity on PSPS Risk

DTS-FAST does not impact PSPS Risk.

Updates to the Activity

A prototype field test installation was completed on a 115kv tower in Martinez and a wood pole in Santa Cruz in 2021. The valuable lessons learned have been updated to streamline designs, increase scalability, and reduce costs. In 2022, we filed a non-provisional patent application for DTS-FAST. For 2023, we have no field installation plans but will be working through the patent examination process.

8.1.2.6.2 Breakaway Connector

Overview of the Activity

This is a new service breakaway disconnect for overhead services to reduce fire ignitions caused by energized secondary services. As of March 31, 2023, it will be required for areas exposed to ignition threats due to trees or branches falling. The breakaway disconnect uses a weak link to provide a predictable point of separation and the service will then fall to the ground de-energized.

Impact of the Activity on Wildfire Risk

To reduce fire ignitions caused by energized secondary services, Electric Distribution Standards and Work Methods departments have approved the service breakaway disconnect. This will help mitigate ignitions caused by trees striking services in areas where services are installed and exposed to tree fall and strike hazards. The only approved size is 1/0 triplex service wire. This encompasses most residential services. It will be installed on new services and service replacement jobs in all areas, including non-fire areas that are exposed to tree fall and strike hazards.

We will not install the Service Breakaway over public roadways so as not to block evacuation routes. Breakaway Connectors, along with our undergrounding, will help mitigate risk for that portion of the line from a riser pole to a customer's service panel eliminating the need to replace a customer's panel and trenching around septic systems.

Impact of the Activity on PSPS Risk

Breakaway disconnect does not impact PSPS Risk.

Updates to the Activity

The service breakaway is no longer in pilot stage. It has been approved for construction. Materials should become available in March 2023.

8.1.2.7 Microgrids

In Sections 8.1.2.1 *through* 8.1.2.12*, the electrical corporation must provide a narrative including the following information for each grid design and system hardening mitigation activity:*

Utility Initiative 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

Impact of the Activity on PSPS Risk

Updates to the Activity: Changes to the initiative since the last WMP submission and a brief explanation as to why those change were made. Discuss any planned improvements or updates to the activity and the timeline for implementation.

OEIS Microgrids Definition: Development and deployment of microgrids that may reduce the risk of ignition, risk from PSPS, and wildfire consequence. "Microgrid" is defined by Public Utilities Code Section 8370(d).

Overview of the Activity

Distribution microgrids provide temporary power, using the existing safe to energize distribution system during a power interruption. Generators of various fuel types are staged at a pre-installed interconnection hub. These microgrids are used to power community resources during a PSPS outage, including critical services such as emergency service providers, grocery and gas stores, and schools.

PG&E continues to develop and deploy microgrids to help reduce the risk of ignitions and to provide back-up power generation during outage events. This reduces customer impacts and creates resilience in the system. This section focuses on the following microgrid solutions:

- Remote Grid;
- Temporary Distribution Microgrids;
- Community Microgrid Enablement Program (CMEP);
- Microgrid Incentive Program (MIP); and
- Microgrid-related technology pilots.

8.1.2.7.1 Remote Grids

Overview of the Activity

Remote Grids provide utility service using standalone, decentralized energy sources and utility infrastructure for continuous, permanent energy delivery to remote locations at the outskirts of the distribution system, in lieu of traditional wires that serve small loads. The Remote Grid facilities include a Standalone Power System (SPS) consisting of local sources of electricity supply. Resolution (Res.) E-5132 approved PG&E's Remote Grid pilot and limits the pilot to two megawatts of total customer load.

Throughout PG&E's service territory, pockets of isolated, small customer loads are served via long electric distribution feeders, some of which traverse the HFTD and require significant annual maintenance, vegetation management, or system hardening solutions. The Remote Grid pilot aims to remove these long feeders and serve customers from a Remote Grid. Reducing overhead lines can reduce fire ignition risk.

Impact of the Activity on Wildfire Risk

Deploying Remote Grids and eliminating overhead lines reduces fire ignition risk, as an alternative to, or in conjunction with, system hardening or other risk mitigation efforts. By removing overhead lines in HFTD, we reduce the risk of ignition from overhead facilities in areas where we install an SPS unit.

Where a Remote Grid is infeasible due to site or customer factors, PG&E may achieve wildfire risk reduction either by: (1) mutual agreement with a property owner to remove PG&E service, known as the Line Elimination Incentive Program, or (2) a mutual agreement for PG&E to buy a property and remove service.

Impact of the Activity on PSPS Risk

The Remote Grid pilot is developing systems that rely on low-voltage secondary distribution and can be excluded from PSPS. Where SPS systems are deployed to enable removal of overhead line, the Remote Grid pilot can mitigate the PSPS risk associated with the overhead circuit segment that is removed, but the program is unlikely to have an impact on broader PSPS mitigation efforts.

Updates to the Activity

The activities performed following the last WMP submission include:

- Validating the performance of the Briceburg Remote Grid (1 SPS) with over 12,000 safe and reliable unit-hours since 06/2021.

- Two new Remote Grids (two SPS) online and operational, bringing the total number of operating systems to three. These new systems serve two customers and will enable removal of two miles of overhead wire in Tier 2 HFTD.

- We have nine SPS at varying stages of development as of Q1 2023.

- We initiated field assessments of more than 50 possible SPS in 2022 with customer outreach and site evaluations.

- We standardized the Remote Grid monitoring and controls platform through selection of New Sun Road via competitive RFP process.

- We standardized the Remote Grid project development process by employing a two-step design process, beginning with a 10 percent-design process to confirm project feasibility followed by full system design and deployment by one of two qualified Engineering, Procurement, and Construction (EPC) vendors using consistent product configurations.

- We achieved greater alignment with California Community Choice Aggregators (CCA) through a new written concurrence from one CCA to deploy one SPS and support from three additional CCAs to start development of new projects.

- PG&E Advice Letter 6623-E, which would allow PG&E to offer Remote Grids as a sole standard service offering under certain conditions, was approved in Res.E-5242.

As a general principle, WMP targets should directly relate to the wildfire risk mitigated. In this case, risk elimination is based on the amount of overhead mileage removed rather than the number of SPS deployed. Despite not having a quantitative target for SPS units installed, Remote Grids will continue to contribute to removal of lines within the overall system hardening goals for distribution.

There are no substantive changes to this initiative expected for 2023, other than the removal of a quantitative target for number of systems deployed.

8.1.2.7.2 Temporary Distribution Microgrids

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 varies in scale and scope, the following design features are likely for each:

- Devices used to disconnect the distribution microgrid 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 use of microgrids for energy resilience allows portions of the larger grid to be de-energized when there is a risk of fire ignition from our lines. When conditions are safe to do so, the circuits within the boundary of the microgrid can be energized, thereby providing pockets of localized energy resilience during a larger de-energization event, intended to decrease risk of wildfire ignition.

Impact of the Activity on PSPS Risk

During PSPS events, sections of the larger grid are de-energized. In these circumstances, the use of microgrids can provide electricity to isolated, safe-to-energize areas to continue to provide power to these customers, despite a larger PSPS event.

Updates to the Activity

No additional temporary distribution microgrid PIH will be built in 2023. The program will close after improvement projects on existing sites are completed. PG&E may develop other distribution microgrids supported by temporary or permanent generation through other programs described in Section 8.1.2.7.3.

8.1.2.7.3 Community Microgrid Enablement Program and Microgrid Incentive Program

Overview of the Activity

CMEP and MIP are programs that support and provide incentives for the development of community-led multi-party microgrids.

Community Microgrid Enablement Program

PG&E introduced the CMEP in Track 1 of the Microgrid Order Instituting Rulemaking (OIR)[123] as part of our proposal to address PSPS mitigation and support energy resilience for our customers and communities. CMEP's objective is to empower communities directly through a combination of technical and financial assistance, as well as through development of the tariffs and agreements necessary to facilitate multi-customer microgrids.

The CMEP program, 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 program consists of four elements:

1. Web-Based Tools and Information: PG&E's Community Resilience Guide (www.pge.com/resilience) provides financial, technical, and interconnection resources for community resilience projects.
2. Enhanced Utility Technical Support: PG&E provides incremental support through a three-stage process to facilitate development of multi-customer microgrids from initial concept exploration, through assessment, and execution.
3. Community Microgrid Enablement Tariff: PG&E submitted a pro forma tariff in Advice Letter 5918-E to govern the eligibility, development, and island and transitional operation of community microgrids.
4. Cost Offsets: PG&E will offset the cost of equipment needed to enable the safe islanding of a community microgrid of up to $3 million per project.

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[123] Rulemaking (R.) 19-09-009. See Appendix E.

Microgrid Incentive Program Overview

In Track 2 of the Microgrid OIR, the CPUC directed electric companies to build on the concept of CMEP and create a new MIP. MIP is intended to fund clean community microgrids, with a focus on disadvantaged and vulnerable populations impacted by grid outages.

The program will use a scoring system based on customer, resilience, and environmental benefits to award funding to selected projects. Three utilities, including PG&E, filed a joint implementation plan in December 2021, which is currently pending CPUC approval.[124]

Impact of the Activity on Wildfire Risk

The use of microgrids for energy resilience allows portions of the larger grid to be de-energized to reduce risk of ignition from our lines. When conditions are safe to do so, the circuits within the boundary of the microgrid can be energized, thereby providing pockets of localized energy resilience during a larger de-energization event.

Impact of the Activity on PSPS Risk

By providing support for community-led multi-customer microgrids, CMEP and MIP reduce PSPS impacts on communities. The programs support the development of local community microgrids, which can provide energy resilience during PSPS or other outage events.

Updates to the Activity

The Redwood Coast Airport Microgrid (RCAM) was built through a California Energy Commission EPIC grant to the Schatz Energy Center and loan from United States of America to the Redwood Coast Energy Authority (a Community Choice Aggregator), in collaboration with PG&E's EPIC 3.11, "Multi-Use Microgrid," project. Launched in 2022,

RCAM is California's first 100 percent renewable energy, front-of-the-meter, multi-customer microgrid. PG&E designed the SCADA interface from the microgrid to the PG&E distribution grid, protection schemes, all associated controls and logic, as well as the required operational control software within PG&E's grid management systems.

The successful deployment of RCAM provides a model for other communities for collaborative development of multi-customer microgrids for energy resilience. Through a distinct subproject of EPIC 3.11, "Multi-Use Microgrid," known as the "Multi-Use Microgrid (Control of BTM DERs)" project, PG&E is developing and demonstrating technical capabilities and operational processes to use Behind-The-Meter (BTM) Distributed Energy Resources (DER) for resiliency in microgrids to enable emissions

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124 R.19-09-009, Proposed Microgrid Incentive Program Implementation Plan of San Diego Gas & Electric Company (SDG&E), PG&E, and Southern California Edison Company (SCE) (Dec. 3, 2021). See Appendix E.

reduction during PSPS events, and to operate reliably in the presence of high penetrations of BTM DERs in multi-customer microgrids.

PG&E also interacted with several communities in 2022 seeking information on how to develop a community microgrid on PG&E's distribution grid. Thus far, PG&E has engaged with more than three dozen communities and customers to explore potential financial and infrastructure support options for developing microgrids and resilience solutions through CMEP.

In December 2021, PG&E, SCE and SDG&E submitted a Joint Implementation Plan for the MIP to the CPUC. In August 2022, parties submitted comments and reply comments to a Staff Proposal on MIP. A final decision on the MIP Implementation Plan is pending.

8.1.2.7.4 Microgrid-Related Technology Pilots

Overview of the Activity

PG&E has initiated a variety of technology-related pilot programs we are evaluating to help mitigate the risk of wildfires and PSPS events. A description of key pilot programs follows.

Mobile BESS Development

PG&E continues to develop our capabilities with mobile battery storage for PSPS mitigation. We are working on making Tesla Megapack batteries mobile, inclusive of support equipment required to supply power as a grid forming or grid following source at primary and secondary voltages. At present, the Megapack fleet is undergoing additional improvements for safety and operations, most notably the inclusion of flame detection and 24/7/365 communication and monitoring SCADA. We have tested the Tesla Megapack batteries and studied their use at the Foresthill site.

Vehicle Grid Integration (VGI) Microgrid Pilot #3

As part of the VGI Decision,[125] PG&E plans to test vehicle-to-grid technology to support resiliency in multi-customer PSPS impacted microgrids. This capability will be tested on vehicle-to-grid chargers installed within PSPS microgrids during 2023. Res.E-5192 approved, with modifications, three VGI pilots proposed by PG&E.[126]

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 batteries. Unlike the traditional use of mobile diesel generators to provide backup power at substations, this CSM is expected to have no operating emissions of greenhouse gases (GHG) or other local air pollutants, while still meeting all operating and cost containment requirements for substation microgrids. The Calistoga CSM, if

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125 D.20-12-029. See Appendix E.

126 Res. E-5192 (May 6, 2022). See Appendix E.

approved and successfully developed, would 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 use of microgrids for energy resilience allows portions of the larger grid to be de-energized when there is a risk of ignition from our lines. When conditions are safe to do so, the circuits within the boundary of the microgrid can be energized, thereby providing pockets of localized energy resilience during a larger de-energization event intended to decrease risk of wildfire ignition.

Impact of the Activity on PSPS Risk

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.

Updates to the Activity

PG&E is working on making Tesla Megapack batteries mobile, inclusive of support equipment required to supply power as a grid forming or grid following source at primary and secondary voltages for PSPS mitigation.

PG&E issued a successful Request for Offers for the CSM pilot resulting in a signed contract that was submitted to the CPUC for approval in December of 2022. Subject to CPUC approval of the contract, the CSM pilot will break ground in 2023 with the goal of being online and ready to operate by September 2024.

PG&E has started coordination with customers on site selection for Phase 1 of the VGI Decision Pilot #3 with the goal of meeting a November 2023 install date for the first five to 10 bi-directional EV chargers within multi-customer microgrids.

8.1.2.8 Installation of System Automation Equipment

In Sections 8.1.2.1 *through* 8.1.2.12*, the electrical corporation must provide a narrative including the following information for each grid design and system hardening mitigation activity:*

Utility Initiative Tracking ID

<u>Overview of the Activity:</u> 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

Impact of the Activity on PSPS Risk

<u>Updates to the Activity:</u> Changes to the initiative since the last WMP submission and a brief explanation as to why those change were made. Discuss any planned improvements or updates to the activity and the timeline for implementation.

<u>OEIS Installation of System Automation Equipment Definition</u>: Installation of electric equipment that increases the ability of the electrical corporation to automate system operation and monitoring, including equipment that can be adjusted remotely such as automatic reclosers (switching devices designed to detect and interrupt momentary faults that can reclose automatically and detect if a fault remains, remaining open if so).

Overview of the Activity

These activities and initiatives focus on the installation of electric equipment that increases the ability to automate system operation and monitoring, including equipment that can be adjusted remotely such as automatic reclosers (switching devices designed to detect and interrupt momentary faults that can reclose automatically and detect if a fault remains and remaining open if it does).

8.1.2.8.1 Installation of System Automation Equipment – Distribution Protective Devices

Utility Initiative Tracking ID: GH-07

Overview of the Activity

As part of the EPSS program described in Section 8.1.8.1, we have installed additional distribution protective devices to mitigate against EPSS reliability impacts. We will install additional Line Reclosers (LR) and Fuse Savers on the highest impacted protective zones to reduce the reliability impact. These will be installed in locations that are within the HFRA or protect equipment within the HFRA.

EPSS is designed to protect beyond fuses and provide ganged operation, thereby reducing back-feed risk. We will replace certain fuse protective zones with LR and Fuse Savers to provide the same ignition reduction benefits but with fewer customers impacted if an outage occurs on the downstream sections. In addition, we will install LR and Fuse Savers in certain locations to provide better fault detection and clearing based on engineering studies.

Impact of the Activity on Wildfire Risk

These devices primarily provide reliability benefits, but they may also have some ignition reduction benefit because new line reclosers are DCD capable. DCD is described in Section 8.1.2.10.1.

Impact of the Activity on PSPS Risk

Additional protective device installations will have minimal impact on reducing PSPS risk and impact. Most of the highest impact fuse devices have already been replaced with automated equipment such as LR and Fuse Savers.

Updates to the Activity

For 2023, we have planned to install devices that will provide significant reliability benefits on fuse tap lines that are in the scope of EPSS. After 2023, we will incorporate additional protection devices into the base reliability work at which point this activity will be discontinued as part of the WMP.

8.1.2.9 Line Removals (in the HFTD)

In Sections 8.1.2.1 *through* 8.1.2.12*, the electrical corporation must provide a narrative including the following information for each grid design and system hardening mitigation activity:*

Utility Initiative 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

Impact of the Activity on PSPS Risk

Updates to the Activity: Changes to the initiative since the last WMP submission and a brief explanation as to why those change were made. Discuss any planned improvements or updates to the activity and the timeline for implementation.

OEIS Line Removals in HFTD Definition: Removal of overhead lines to minimize the risk of ignition due to the design, location, or configuration of electric equipment in HFTDs.

Overview of the Activity

Line de-energization, grounding, and line removal are activities that PG&E employs to deactivate a facility if it is nonoperational or no longer needed and located within an HFTD.

8.1.2.9.1 Line Removal (in the HFTD) – Transmission

Overview of the Activity

PG&E follows the procedures and requirements in Management of Idle Electric Transmission Line Facilities Procedure (TD-1003P) to investigate potential idle facilities. When these facilities are identified and confirmed to be within an HFTD and no longer having an operational need, they are prioritized for de-energization, grounding, and/or removal. Grounding of a de-energized line addresses residual wildfire risk of induction from nearby energized line(s), until conductor removal or repurposing of the facilities can occur.

Transmission lines may also be considered for temporary or seasonal de-energization, depending on the operational needs and wildfire risk associated with the line. Transmission lines may be removed as part of the idle facility process, or through other work such as line re-routing or re-building. As referenced in SED-6,[127] PG&E has embarked on a 10-year plan to remove permanently abandoned transmission lines.

Impact of the Activity on Wildfire Risk

Removal of idle lines, including de-energization and grounding, eliminates wildfire risk associated with transmission assets.

Impact of the Activity on PSPS Risk

Removal of idle lines, including of de-energization and grounding, eliminates PSPS risk associated with transmission assets.

Updates to the Activity

Transmission line removals will continue to progress through 2023-2025. Line removal in HFTD is part of Target GH-05 in Section 8.1.1.2.

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[127] PG&E Removal Plan for Permanently Abandoned Transmission Facilities as part of Res.SED-6: PG&E's 10-year plan for identifying, investigating, and documenting Idle transmission facilities that have been determined by PG&E to have no near-future use and are considered "permanently abandoned" transmission facilities is an essential part of PG&E's strategy in minimizing wildfire risks and ensuring public safety. CPUC, PG&E Removal Plan for Permanently Abandoned Transmission Facilities, PG&E Update to Res. SED-6, available at: <https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/safety-and-enforcement-division/acos-and-aeos/pge-sed-6-removal-plan-for-transmission-idle-facilities.pdf>, accessed January 30, 2023.

8.1.2.9.2 Line Removal (in the HFTD) – Distribution

Overview of the Activity

A distribution line may be considered for removal when it 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. PG&E follows the procedures and requirements in the TD-2459P-01 Idle Facility Program Procedure to investigate potential idle facilities and determine if they can be permanently removed from service.

2. Circuit Re-Route: Rearrangement or re-alignment of the existing circuit path to serve customers through an alternate route. PG&E reviews the targeted circuit segment for redundant distribution ties in high-risk areas. It may be possible for the removal of certain circuit segments while having little impact on operational flexibility, which provides a highly cost-effective measure to reduce wildfire risk.

3. Remote Grid: Application of the Remote Grid alternative, as discussed in Section 8.1.2.7.1, can result in existing assets no longer being operationally necessary and eligible for removal.

Impact of the Activity on Wildfire Risk

Line removal eliminates the 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.

Impact of the Activity on PSPS Risk

If an overhead distribution line is in an HFTD that is impacted by PSPS events, complete removal of the line can help mitigate or reduce the size and impact of a PSPS event since any active customers would be served through an alternate method.

Updates to the Activity

Overhead line removal will progress as the application of remote grids continue to mature (see Section 8.1.2.7.1). As discussed in PG&E's 2022 Revised WMP, line removal projects are difficult to forecast for four reasons: (1) customers considering a remote grid project may decline that option and choose wired service instead; (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 which 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.

PG&E's overall System Hardening program includes the combination of Covered Conductor Installation (Section 8.1.2.1), Undergrounding (the System Hardening portion of Section 8.1.2.2) and Line Removal. The estimated mileage contribution forecasts of the three sub-programs within System Hardening are found in Table PG&E-8.1.2-4

below (with non-System Hardening undergrounding as part of the Butte County Rebuild program included for reference as well).

**TABLE PG&E-8.1.2-4:
OVERALL SYSTEM HARDENING MILEAGE FORECAST**

Year	Estimated Overhead Covered Conductor Miles	Estimated System Hardening Undergrounding Miles	Estimated Line Removal Miles	Overall System Hardening Target	Estimated Butte County Rebuild Undergrounding Miles
2023	110	280	30	**420**	70
2024	75	380	15	**470**	70
2025	50	515	15	**580**	35
2026	50	750	15	**815**[(a)]	0
2023-2026	285	1,925	75	**2,285**	175

(a) The 2023 WMP requires annual targets for 2023-2025. The 2026 miles are provided as a forecast only.

As noted in Section 8.1.2.1, PG&E's annual targets for system hardening work are the overall system hardening targets. The estimated mileage forecasts for each sub-type of hardening, including line removal, will vary from the actual mileage completed in each year and are not individual targets.

8.1.2.10 Other Grid Topology Improvements to Minimize Risk of Ignitions

In Sections 8.1.2.1 *through* 8.1.2.12*, the electrical corporation must provide a narrative including the following information for each grid design and system hardening mitigation activity:*

Utility Initiative 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

Impact of the Activity on PSPS Risk

Updates to the Activity: *Changes to the initiative since the last WMP submission and a brief explanation as to why those change were made. Discuss any planned improvements or updates to the activity and the timeline for implementation.*

OEIS Other Grid Topology Improvements to Minimize Risk of Ignitions Definition: *Actions taken to minimize the risk of ignition due to the design, location, or configuration of electric equipment in HFTDs not covered by another initiative.*

8.1.2.10.1 Downed Conductor Detection Devices

Utility Initiative Tracking ID: GM-06

Overview of the Activity

High impedance faults are conditions where faults do not result in large enough fault current (a function of fault resistance) that a protective device and traditional protection schemes can reliably sense and de-energize the circuit segment. These situations can create a potential ignition source.

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 being 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.

Impact of the Activity on Wildfire Risk

Installation of DCD on existing, new, and retrofitted recloser controllers is expected to reduce the number of ignitions due to high impedance line-to-ground faults by quickly detecting and de-energizing the fault, which is the primary existing gap in EPSS protection on primary overhead distribution conductor. Approximately half of the CPUC reportable ignitions in HFTD that occurred in 2022 while EPSS was enabled were the result of high-impedance faults.

Impact of the activity on PSPS Risk

System Automation installation of DCD on existing Recloser controllers does not impact PSPS.

Updates to the Activity

This is a new initiative that will likely continue from 2023-2025. Target GM-06 discusses our plans for DCD during the relevant WMP timeperiod.

8.1.2.10.2 Installation of System Automation Equipment – Installation of Devices to Eliminate High Impedance Back-feed Conditions

Overview of the Activity

A Fuse Saver is a flexible, cost-effective, intelligent device which can replace fuses and have the capability to 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.

Impact of the Activity on Wildfire Risk

Fuse Saver installations will mitigate fire risk associated with downed wire events on tap line through ganged operated de-energization preventing certain types of high impedance faults from occurring.

Impact of the Activity on PSPS Risk

Planned fuse saver installations for 2023 will have minimal impact on reducing PSPS risk and impact because most of the highest impacted fuse devices have already been replaced with automated equipment.

Updates to the Activity

In 2021 and 2022, we replaced 155 existing fused cutouts with Fuse Savers. We installed 74 Fuse Savers in 2021 and 81 units in 2022.

We have focused on fused cutouts experiencing a wire-down outage, multiple days of R3, R4, or R5 Fire Risk Days, in Tier 2 or Tier 3 HFTD and included line-to-line connected transformers. As part of the enablement of EPSS and its objective to protect all sections including fused lines with ganged protection using existing devices, installation of Fuse Savers now has less direct impact on reducing ignition risk. Previously identified projects will continue to be built in 2023 and 2024 at which point the activity will be completed.

8.1.2.10.3 Motor Switch Operator Switch Replacement

Utility Initiative Tracking ID: GH-09

Overview of the Activity

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. Despite these switches being understood to meet California Department of Forestry and Fire Protection (CAL FIRE) exempt criteria for not posing an ignition risk during normal operation, PG&E crews identified a risk that some MSO switches were reported to exhibit an arc flash during operation. PG&E halted further installations of MSO switches in late 2019. This activity replaces the MSO switches with reclosers, subsurface equipment, and other vacuum switch equipment that is approved for current usage in HFTD.

Impact of the Activity on Wildfire Risk

PG&E has eliminated the risk of ignition from the operation of MSOs by implementing guidance document De-Energized Operation of Inertia SCADA MSO (TD-076253-B005). Implementation of this control requires that any operation of the device (either open or close) be done while the device is de-energized to mitigate all risk of ignition.

Impact of the Activity on PSPS Risk

A consequence of being restricted to operating MSOs only while in a de-energized state is that a more upstream/source-side device must be operated instead, which results in more customers being affected by the PSPS event or other outage. By replacing the MSOs, originally intended functionality to support PSPS is restored.

Currently PG&E does not use MSOs as the primary device when de-energizing customers for PSPS conditions. If an MSO is intended to be the primary load break device for a PSPS circuit, PG&E will first de-energize the next upstream device from the intended MSO to break load then open the MSO and re-energize from the upstream device to the MSO. This results in additional customers located between the intended MSO and the next upstream device having a short duration outage. By replacing the MSOs, PG&E will be able to use the intended device for de-energization and will not have to de-energize the upstream customers for the short period.

Updates to the Activity

The primary work that will occur in 2023 and 2024 will be to finish replacing the remaining 47 MSO switches that were identified as of January 1, 2023, with suitable alternative technology that will reenable those locations with automated capability to segment during PSPS events. This is described in target GH-09 "Distribution Line Motor Switch Operator (MSO)." After 2024, we anticipate that removal of any additional MSO switches identified beyond the 47 located within HFTD or HFRA areas, or are energizing line sections that feed into HFTD or HFRA, will be removed from the system.

8.1.2.10.4 Surge Arresters

Utility Initiative Tracking ID: GH-08

Overview of the Activity

The surge arrester program replaces existing non-exempt surge arresters with exempt surge arresters at locations with potentially deficient grounding. The exempt surge arresters have less propensity to cause a fire ignition. In addition, we address common grounding by separating out the grounding on poles where surge arrestors and transformers are co-located and shared a single ground. Surge protection is an initial defense against the instant or gradual destruction of electrical equipment. By upgrading the equipment, continuing to separate the grounds, and conducting ground and impedance improvements, lightning strikes, and other surges safely dissipate to their dedicated surge arrester ground, while not affecting the separately grounded transformer co-located on the same pole.

Impact of the Activity on Wildfire Risk

The non-exempt surge arresters are replaced with new surge arresters which are considered CAL FIRE exempt and certified as equipment which reduces the likelihood of an ignition during normal operation.

Impact of the activity on PSPS Risk

This program does not have any impact on PSPS risk.

Updates to the Activity

This program is targeting the replacement of known non-exempt surge arrester locations in HFTD and HFRA that have been identified to have potentially deficient grounding. If the surge arresters observed show signs of deterioration, they are replaced with an exempt surge arrester as part of the maintenance program; additionally, as part of any new construction, non-exempt surge arresters get changed to exempt surge arresters. PG&E expects to complete the program by 2023, barring external factors such as access issues.

In 2022, we planned to close out all known HFTD locations with known grounding issues, which we anticipated to be 4,590 at the time of the 2022 WMP filing. However, there were fewer cancellations than projected in 2022. As a result, and after reviewing our surge arrester data throughout the year, we ended up exceeding our numeric target by completing 4,621 locations. However, we still have 139 locations left to complete the known HFTD locations with potentially deficient grounding, as of data available on January 1, 2023. These locations were not completed in 2022 due to access issues, customer refusals, and poles that need replacement before surge arrester work can take place. These 139 remaining locations will be executed in 2023, barring external factors.

In addition, in 2023 we are expanding the scope to include surge arresters in HFRA region. Additional information can be found in Section 8.1.1.2 in the Target GH-08.

8.1.2.10.5 Non-Exempt Expulsion Fuses

Utility Initiative Tracking ID: GH-10

This program reduces the consequence of potential ignitions by replacement and/or removal of non-exempt fuses. In general, the risk of ignition associated to a fuse on a line is reduced through the complete removal and/or replacement of non-exempt equipment with exempt equipment. Fuses are intended to protect the main line of the distribution feeder from faults occurring on the laterals.

Impact of the Activity on Wildfire Risk

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. When planning non-exempt fuse replacement, engineers conduct coordination studies to ensure protective devices are adequate to operate during the maximum available fault current and ensure that devices will properly operate in sequence to isolate the fault and minimize customer impact. In most cases, coordination is not interrupted when replacing non-exempt fuses with exempt equipment as described in this initiative.

Occasionally, when replacing existing non-exempt fuses with exempt fuses, the exempt fuse will disrupt the protection scheme for that circuit. In these cases, PG&E will be deploying Solid Blade switches to support operational flexibility and protect coordination. Even though Solid Blades are currently non-exempt devices, this strategy allows PG&E to eliminate the non-exempt fuse devices that operate automatically and hence pose a higher ignition risk. PG&E standard requires a crew with a QEW operator to be present at the site when a Solid Blade is operated. Additionally, the operator uses a load breaking tool when operating the switch, which diverts the load current through the load buster tool and mitigates the chances of a spark.

PG&E is currently in the process of seeking exemption status for the Solid Blade switch. Until the exemption status is approved by CAL FIRE, PG&E will also continue to maintain a firebreak around the poles that have Solid Blade installation to provide additional control against any ignition risk. As of January 2023, PG&E is not aware of any ignitions that have been caused due to the operation of a Solid Blade.

Impact of the Activity on PSPS Risk

This program has minimal impact on reducing PSPS risk and impact. Most of the highest impact fuse devices have already been replaced with automated equipment such as LR and Fuse Savers.

Updates to the Activity

PG&E plans to maintain the 2022 pace of replacing expulsion fuses (~3,000 per year) prioritized based on WDRM v2 consequence, while factoring in potential impacts of EPSS on locations identified for replacement.

The number of non-exempt fuses to be removed in the targeted locations is approximately 7,400. As indicated in Target GH-10, we plan to remove these non-exempt fuses over the next three years. In our 2025 WMP update, we anticipate updating the number of non-exempt fuses to be removed in 2025 as we continue to work down this population. Additional information on the Target GH-10 can be found in Section 8.1.1.2.

8.1.2.11 Other Grid Topology Improvements to Mitigate or Reduce PSPS Events

In Sections 8.1.2.1 *through* 8.1.2.12*, the electrical corporation must provide a narrative including the following information for each grid design and system hardening mitigation activity:*

Utility Initiative 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

Impact of the Activity on PSPS Risk

Updates to the Activity: *Changes to the initiative since the last WMP submission and a brief explanation as to why those change were made. Discuss any planned improvements or updates to the activity and the timeline for implementation.*

OEIS Other Grid Topology Improvements to Mitigate or Reduce PSPS Events Definition: *Actions taken to mitigate or reduce PSPS events in terms of geographic scope and number of customers affected not covered by another initiative.*

Overview of the Activity

This section includes actions taken to mitigate or reduce PSPS events, in terms of geographic scope and number of customers affected, not covered by another initiative.

8.1.2.11.1 Other Grid Topology Improvements to Mitigate or Reduce PSPS Events – Transmission

Overview of the Activity

PG&E has been installing sectionalizing devices on our transmission system to allow us to segment the transmission circuits traversing the HFTD.

Impact of the Activity on Wildfire Risk

This initiative does not directly impact wildfire risk. Indirectly, when switches or poles are replaced during installation of sectionalizing devices, the newer assets have lower wildfire risk because they are up to current standards and not worn or aged.

Impact of the Activity on PSPS Risk

These devices allow operational flexibility to reduce the scope and impact of PSPS events. For example, if a transmission asset needs to be de-energized during a PSPS event, and there are no switches or we are unable to sectionalize the transmission line, the entire line must be de-energized for that asset. By being able to sectionalize lines, particularly those with tapped customers, we gain the flexibility to only de-energize a portion of the line with the at-risk asset, rather than the entire line. Certain customers may remain in-service while still de-energizing the necessary portions of the line during PSPS events. The number of customer impacts avoided during a PSPS event depends on weather and asset health at the time of the PSPS event.

Updates to the Activity

Over the past few years, PG&E has installed multiple sectionalizing devices to minimize customer impact from PSPS, including 15 switches in 2022. We are not planning to install additional devices specifically for PSPS mitigation from 2023 to 2025. If inspections of existing switch assets reveal that replacement is needed due to condition, upgrades can occur at that time.

A review of the current 10-year PSPS lookback was conducted. Of the 111 lines most likely to be in scope for PSPS based on historical weather data, all the lines have either already been sectionalized or do not presently need to be sectionalized. One example of a line that would not need to be sectionalized is a line that goes from one substation to another, with no junctions or tapped stations in between. The 10-year lookback is updated annually and may drive adjustment to the program in future years.

8.1.2.11.2 Other Grid Topology Improvements to Mitigate or Reduce PSPS Events – Distribution

Overview of the Activity

Installing remotely operable SCADA sectionalizing devices and manually operated sectionalizing devices on the distribution system supports PG&E's ability to segment the distribution circuits close to designated meteorology shut-off polygons and reduce the customer impact and the scope of PSPS events.

Impact of the Activity on Wildfire Risk

Many of the remotely operable SCADA sectionalizing devices also are capable of fault detection and isolation and can be equipped with EPSS to better help sectionalize and protect the system and, in conjunction with existing protective devices, provide wildfire risk reduction.

Impact of the Activity on PSPS Risk

During PSPS events, distribution sectionalizing devices are used to isolate high-risk areas from safe-to-energize areas, minimizing the scope of the event.

Reducing duration of outage events (PSPS/EPSS) by using automated sectionalizing devices, rather than depending on manually operated devices, means that the device can be operated remotely as close to the prescribed shut-off time as possible. Additionally, reducing the scope of PSPS events reduces the inspection and restoration time to allow power to be restored quickly.

Updates to the Activity

Most of the highest impact locations have already been sectionalized with automated equipment, so there is reduced benefit (in terms of number of customers likely to benefit from such devices during PSPS events) when compared to work performed in previous years. For this reason, we are de-prioritizing the program in 2023, and instead will focus on reducing reliability impacts with additional protective devices as part of Target GH-07, "Distribution Sectionalizing Devices."

8.1.2.11.3 Other Grid Topology Improvements to Mitigate or Reduce PSPS Events – Substation

Overview of the Activity

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, the 10-year PSPS lookback dataset was used to identify substations most likely to be impacted by PSPS events. In doing so, PG&E identified and executed the upgrade from transformer primary fuse protection to circuit switcher and relay protection devices for transformer bank #1 at the Rincon substation.

Impact of the Activity on Wildfire Risk

Upgrading power transformer primary protection fuses with interrupting devices, such as circuit breakers or circuit switchers, inherently allows for faster clearing times for potential substation power transformer internal faults or through faults, further reducing equipment failure and the potential for ignition risks.

Impact of the Activity on PSPS Risk

Upgrading power transformer primary fuse protection with interrupting devices minimizes PSPS scope and duration by reducing the amount of line de-energizations needed as well as eliminating the need to deploy field personnel to the substation to perform switching operations.

Updates to the Activity

As the 10-year PSPS lookback data set is refreshed annually, PG&E will continue to identify opportunities for this type of protection upgrade.

8.1.2.12 Other Technologies and Systems

In Sections 8.1.2.1 *through* 8.1.2.12*, the electrical corporation must provide a narrative including the following information for each grid design and system hardening mitigation activity:*

Utility Initiative Tracking ID

<u>Overview of the Activity:</u> 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

Impact of the Activity on PSPS Risk

<u>Updates to the Activity:</u> Changes to the initiative since the last WMP submission and a brief explanation as to why those change were made. Discuss any planned improvements or updates to the activity and the timeline for implementation.

<u>OEIS Other Technologies and Systems Definition:</u> Other grid design and system hardening actions which the electrical corporation takes to reduce its ignition and PSPS risk not otherwise covered by other initiatives in this section.

8.1.2.12.1 Other Technologies and Systems – Avian Protection Plan

Overview of the Activity

PG&E has an Avian Protection Plan that is designed to protect the avian population from contacting electrical components in our service territory. The plan applies to both the transmission and distribution overhead electrical facilities. Avian protection measures may also improve system reliability, safety, and ignition risk.

Impact of the Activity on Wildfire Risk

Certain avian protection measures may improve safety and ignition risks. We are working to ensure adequate separation between energized components by insulating these components. This can prevent incidental avian contact, which can potentially lead to electrical flashover and wildfire ignition.

Impact of the Activity on PSPS Risk

N/A

Updates to the Activity

PG&E is currently working on a transmission Avian Risk model. The Wildfire Distribution Risk Model already considers avian-related outages.

8.1.2.12.2 Other Technologies and Systems – Substation Animal Abatement

Overview of the Activity

PG&E employs a substation animal abatement program which focuses on mitigating animal-related contact events within substations and power generation switchyards with operating voltages of 34.5kV and below. This includes both avian and ground animals. This program 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. The animal abatement program is documented within the Substation Animal Abatement Measures Procedure (TD-3350P-10).

There are two animal abatement approaches for substations and power generation switchyards:

- Small-Scale Animal Abatement (Single Equipment): Identified animal abatement issues are managed by the responsible substation maintenance headquarters using the corrective notification process. These notifications are prioritized based on an in-field assessment. Typically, corrective notifications generated for animal abatement are completed within one year of the issue being identified, but can sometimes be bundled into larger projects.

- Large-Scale Animal Abatement (Large Section or Entire Substation): Animal abatement equipment is applied to substations with qualifying outdoor distribution voltage equipment (typically 34.5kV and below). There are projects to abate equipment that has not been abated previously, to re-abate deteriorated equipment, and to add abatement to areas where it is missing. These projects are initiated based on corrective notifications, through direct feedback from maintenance headquarters, or recommendations from SMEs. Large scale animal abatement projects are prioritized using historical animal contact events, substation voltage, customer counts, location, and wildfire risk. By the end of 2022, PG&E completed a multi-year project to apply animal abatement mitigations at all targeted HFTD transmission and distribution substations. By the end of 2025, PG&E will complete animal abatement mitigation at all HFTD power generation switchyards.

Impact of the Activity on Wildfire Risk

Substation animal-related arc flashes are mitigated by through various mitigation materials and techniques that include pole-mounted climbing guards, critter covers/guards, tape-wraps, physical separation, shields, raptor-safe construction, electric fences, or other deterrents on or near exposed energized components of substation equipment. These mitigation measures intend to reduce ground or avian species induced outages, equipment failures, and risks of wildfire propagation outside the substation.

Impact of the Activity on PSPS Risk

There is no impact on PSPS risk.

Updates to the Activity

PG&E will continue to execute small scale animal abatement as identified through the corrective notification process. Additionally, PG&E will continue to monitor animal abatement project triggers at substations to identify and prioritize additional large-scale projects as needed.

PG&E will continue to implement animal abatement mitigation at HFTD power generation switchyards.

PG&E will continue the installation of animal abatement products and mitigation techniques identified within Substation Animal Abatement Measures Procedure (TD-3350P-10) on all new construction projects (i.e., transformer and circuit breaker replacements, bus conversions and other temporary and permanent installations).

Substation Animal Abatement Effectiveness Study

In 2023, PG&E is partnering with the Electric Power Research Institute (EPRI) to perform a data-driven evaluation of animal intrusion issues in PG&E substations. It is an update to the existing substation animal abatement activity. EPRI's Program 51 is dedicated to environmental issues surrounding the transmission and distribution of electrical power. The methodology includes the development of impact metric(s), identification of most damaging species (avian, mammal) and mechanisms (nesting, contact with overhead components, equipment intrusion, etc.), and application of reliability growth models to assess evolution and effectiveness of the problem over time.

In addition, this study will explore benchmarking techniques to evaluate effectiveness of animal abatement methods by comparing substations by geographical area and/or self-benchmarking based on historical data.

8.1.3 Asset Inspections

In this section, the electrical corporation must provide an overview of its processes and procedures for inspecting it assets.

The electrical corporation must first summarize details regarding its vegetation management inspections in Table 8-6. 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 (i.e., patrol, detailed, aerial, climbing, and LiDAR).*
- *Governing Standards and Operating Procedures: Identify the regulatory requirements and the electrical corporation's procedures/processes.*

In this section we summarize our processes and procedures for asset inspections, including details of the inspection process.

Inspection process details are included in Table 8-6, which lists PG&E's transmission, distribution, and substation asset inspection programs, methods of inspections, and governing standards and operating procedures.

TABLE 8-6:
ASSET INSPECTION FREQUENCY, METHOD, AND CRITERIA

Type	Inspection Program	Frequency or Trigger	Method of Inspection	Governing Standards and Operating Procedures
Transmission	Detailed Ground	3 years or WTRM	Ground visual	GO 165, TD-8123P-100, TD-1001M, TD-1001P-13
Transmission	Detailed Aerial	3 years or WTRM	Drone, helicopter, or aerial lift	GO 165, TD-8123P-100, TD-1001M, TD-1001P-13
Transmission	Detailed Climbing	3 years	Climbing	GO 165, TD-8123P-100, TD-1001M, TD-1001P-13
Transmission	IR	Tier 3: 1 year; Tier 2/Zone 1/HFRA: 3 years	Helicopter	GO 165, TD-8123P-100, TD-1001M, TD-1001P-13 TD-1001P-14
Transmission	Corona	Tier 3: 1 year; Tier 2/Zone 1/HFRA: 3 years	Helicopter	NA – Pilot
Transmission	Intrusive Pole Inspection	10 years or as triggered	Ground/ hole boring	GO 165, TD-2325S
Transmission	Switch Function Tests	8 years	Ground/Aerial with some function tests as triggered	GO 165, TD-1006P-02 and associated bulletins, TD-1001M
Transmission	Patrol	Every year not inspected by ground or aerial	Helicopter or ground	GO 165, TD-8123P-100, TD-1001M, TD-1001P-13
Transmission	LiDAR Assessment	TBD – Pilot	Helicopter	NA – Pilot
Transmission	Below Grade Assessment	TBD – Pilot	Ground/ digging	NA – Pilot/In development
Transmission	Conductor Measurement	TBD – Pilot	LineVue robotic device	NA – Pilot
Transmission	Ultrasonic Inspection	TBD – Pilot	Ground with measurement device	NA – Pilot

TABLE 8-6:
ASSET INSPECTION FREQUENCY, METHOD, AND CRITERIA
(CONTINUED)

Type	Inspection Program	Frequency or Trigger	Method of Inspection	Governing Standards and Operating Procedures
Transmission	Corrosion Climbing Inspection	TBD – Pilot	Climbing	NA - Pilot
Transmission	Proactive Sampling/Testing	TBD – Pilot	Laboratory or field analysis	NA - Pilot
Distribution	Detailed Ground Inspection	WDRMv3	Ground visual	Electric Distribution Preventive Maintenance (EDPM) Manual, TD-8123M
Distribution	IR Inspection	As -needed to investigate emerging issues	Ground IR	TD-2022P-01
Distribution	Intrusive Pole Inspections	Approximately 10 Years or As Triggered	Ground/ hole-boring	TD-2325S & TD-2325P-01
Distribution	LiDAR-Based Pole Loading Assessments	First time analysis – does not have a recurring frequency	Helicopter and vehicle	N/A
Distribution	Patrols	All areas not covered by detailed ground inspection	Ground visual	EDPM, TD 2305-M
Distribution	Aerial Pilot	WDRM v3	Drone	NA Pilot
Distribution	Overhead Equipment Inspections	Annually	Ground visual	TD-2302P-05
Substation	Supplemental Ground Inspection	3-years or in-year based on risk	Ground	TD-3328S
Substation	Supplemental Aerial (drone) Inspection	3-years or in-year based on risk	Aerial	TD-3328S
Substation	Supplemental IR Inspection	3-years or in-year based on risk	Ground IR	TD-3328S

8.1.3.1 Asset Inspections – Transmission

Process

In this section, the electrical corporation must provide an overview of the individual asset inspection program, including inspection criteria and the various inspection methods used for each inspection program.

Include relevant visuals and graphics depicting the workflow and decision-making process the electrical corporation uses for the inspection program.

Frequency or Trigger

In this section, the electrical corporation must identify the frequency (including how frequency may differ by HFTD Tier or other risk designation[s]) or triggers used in the inspection program, such as inputs from the risk model.

If the inspection program is schedule-based, 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.

Accomplishments, Roadblocks, and Updates

In this section, the electrical corporation must discuss:

- *Noteworthy accomplishments for the inspection program since the last WMP.*
- *Roadblocks the electrical corporation has encountered while implementing the inspection program and how the electrical corporation has addressed the roadblocks.*
- *Changes/updates to the inspection program 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 5 years (i.e., references to and strategies from pilot projects and research).*

Transmission overhead assets in the HFTD and HFRA are inspected in accordance with the Electric Transmission Preventive Maintenance (ETPM) and informed by the Failure Modes and Effects Analysis (FMEA). Methods of inspection include detailed ground, detailed aerial (drone, aerial, or aerial lift), climbing, IR/corona, patrols, intrusive pole test, switch test, and other pilot methods such as below grade assessment. Through our inspection program, we seek to proactively identify and mitigate asset conditions which could fail and lead to an ignition.

Figures PG&E-8.1.3-1 and PG&E-8.1.3-2 at the end of this section show our Transmission inspection process.

8.1.3.1.1 Ground Detailed Inspection

Utility Initiative Tracking ID: AI-02

Process

Transmission overhead assets in the HFTD and HFRA are inspected in accordance with the ETPM and informed by the FMEA. Ground inspections are performed visually, via an inspector on the ground. These inspections seek to identify asset conditions which could lead to an ignition.

Frequency or Trigger

Structures in the HFTD and HFRA are inspected via ground inspection at least once every three years. In addition to this baseline cycle, structures may also be added to the annual inspection scope based on:

- Wildfire risk informed by the Transmission Composite Model (TCM) annualized probability of failure and Wildfire Consequence; and
- Other factors such as inspection result trends, terrain/fire suppression considerations, etc.

We evaluate the need for additional inspections each year based on a snapshot of the wildfire risk data.

Accomplishments, Roadblocks, and Updates

In 2022, PG&E identified and inspected the highest wildfire risk and consequence assets while continuing to inspect a baseline of 33 percent of all HFTD/HFRA.

Specific accomplishments in 2022 include:

- 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.
- Component testing was completed to advance understanding of failure conditions. Results are used to confirm or update inspection checklists and job aids.
- Updating the inspections checklist to also address emerging issues from inspectors and ensuring alignment between ground and aerial inspection checklists.
- Streamlining the monthly inspections validation process used to ensure new structures added to the asset registry are inspected.

Pre-2023, transmission circuits sharing a structure are photographed as a single asset. In 2023, we are evaluating and implementing Information Technology (IT) solutions to better independently reflect multiple circuits sharing a single structure. In 2023, we will implement an inspector assessment process to improve inspector effectiveness. We will introduce a staggered approach to ground and aerial inspections leaving less time between inspections throughout the 3-year baseline cycle.

8.1.3.1.2 Aerial Detailed Inspection

Utility Initiative Tracking ID: AI-04

Process

Transmission overhead assets in the HFTD and HFRA are inspected in accordance with the ETPM and/or the FMEA. Aerial inspections are performed via drone, helicopter, or aerial lift, with desktop image review. These inspections seek to identify asset conditions which could lead to an ignition.

Frequency or Trigger

PG&E conducts aerial detail inspections of structures in the HFTD and HFRA at least once every three years. In addition to this baseline cycle, structures may also be added to the annual inspection scope based on:

- Wildfire risk informed by the TCM annualized probability of failure and Wildfire Consequence; and
- Other factors such as inspection result trends, terrain/fire suppression considerations, etc.

We evaluate the need for additional inspections each year based on a snapshot of the wildfire risk data.

Accomplishments, Roadblocks, and Updates

In 2022, PG&E identified and inspected the highest wildfire risk and consequence assets while continuing to inspect a baseline of 33 percent of all HFTD/HFRA.

Specific accomplishments in 2022 include the following:

- Component testing was completed to advance understanding of failure conditions. Results are used to confirm or update inspection checklists and job aids.
- Updating the inspections checklist to also address emerging issues from inspectors and ensuring alignment between ground and aerial inspection checklists.
- Streamlining the monthly inspections validation process used to ensure new structures added to the asset registry are inspected.

- Through EPIC 3.41, “Drone Enablement,” PG&E is demonstrating Beyond Visual Line of Sight (BVLOS) drone-based asset inspection operations including the further automation of transmission inspections.

In 2023, we will introduce a staggered approach to ground and aerial inspections leaving less time between inspections throughout the 3-year baseline cycle.

8.1.3.1.3 Climbing Detailed Inspection

Utility Initiative Tracking ID: AI-05

Process

Transmission overhead assets in the HFTD and HFRA are inspected in accordance with the ETPM and/or FMEA. Climbing inspections are performed visually by an inspector climbing the structure. Measurements are also taken for structures climbed with internal guy wires. We conduct these inspections to identify asset conditions which could lead to an ignition.

Frequency or Trigger

PG&E conducts a climbing inspection on structures in the HFTD and HFRA that are 500 kV or contain internal guy wires at least once every three years. In addition to this baseline cycle, structures may also be added to the annual inspection scope based on:

- Wildfire risk informed by the TCM annualized probability of failure and Wildfire Consequence; and

- Other factors such as inspection result trends, terrain/fire suppression considerations, etc.

We evaluate the need for additional inspections each year based on a snapshot of the wildfire risk data.

Accomplishments, Roadblocks, And Updates

In 2022, PG&E identified and inspected the highest wildfire risk and consequence assets while continuing to inspect a baseline of 33 percent of all HFTD/HFRA.

Specific accomplishments in 2022 include:

- 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;

- For most tower configurations, the inspection form included digital collection of internal guy tension measurements. All tower configurations will be included in the 2023 digital inspection checklist; and

- Streamlining the monthly inspections validation process used to ensure new structures added to the asset registry are inspected.

Pre-2023, transmission circuits sharing a structure are photographed as a single asset. In 2023, we are evaluating and implementing IT solutions to better independently reflect multiple circuits sharing a single structure. We will introduce a staggered approach to ground and aerial inspections leaving less time between inspections throughout the 3-year baseline cycle.

8.1.3.1.4 Infrared Inspection

Utility Initiative Tracking ID: AI-06

Process

Transmission overhead assets in the HFTD and HFRA are inspected in accordance with the ETPM and/or FMEA. IR inspections are performed via helicopter and are conducted simultaneously with corona inspections to proactively identify asset conditions which could result in an ignition. IR inspection effectiveness depends on adequate circuit loading and weather conditions. For example, a circuit on the coast may have IR performed in the winter when lines are more heavily loaded in order to produce more effective results.

Frequency or Trigger

Transmission IR inspections are completed on HFTD Tier 3 lines annually and on HFTD Tier 2 lines at least once every three years.

Accomplishments, Roadblocks, and Updates

IR is most effective when transmission lines are adequately loaded. This presents a challenge when scheduling IR inspections across the system, which needs to balance historical loading patterns along with other conditions such as weather. In 2022, the IR inspection team was further trained in thermography and uvigraphy. Additionally, a methodology was developed to optimize the workplan for IR inspections using historical electrical loading. These improvements aim to increase inspection effectiveness by achieving higher line loading at the time of inspection as well as precision inspection review through the trained team. In 2023, improvements are being explored to increase granularity of historical loading assessment to the line segment level rather than across the entire line.

8.1.3.1.5 Intrusive Pole Inspection

Process

Transmission overhead assets in the HFTD and HFRA are inspected in accordance with the ETPM and/or FMEA. Intrusive pole inspections may include visual inspection, sound inspection (hammer test), below-grade external inspection (excavation), intrusive inspection (bore and probe tests), effective circumference evaluation, remaining strength calculation, and alternative pole evaluation. These inspections seek to identify asset conditions (primarily wood pole decay) which could lead to an ignition.

Frequency or trigger

Assets are selected for an inspection cycle primarily by the date the wood pole was installed and put into service. PG&E performs an intrusive inspection for each pole on an approximate 10-year cycle, intrusively inspecting roughly 10 percent of wood poles annually. Information from the WTRM may add additional poles to the inspection plan.

Accomplishments, Roadblocks, and Updates

In 2022 PGE implemented revisions made to TD-2325, which incorporated industry best practices as well as adjusted the pole rejection criteria. PGE also performed a proof-of-concept test to track our TCM Wood Decay Module against data from the field.

In 2023, we will continue to use inspection data to further refine our Wood Decay Model.

8.1.3.1.6 Switch Function Testing

Process

Transmission overhead assets in the HFTD and HFRA are inspected in accordance with the ETPM and/or FMEA. Switch function tests are performed either by a detailed visual inspection and/or a functional exercise to ensure the switch is operating properly. Lubrication and battery testing may also be included depending on the type of switch. These inspections seek to identify asset conditions which could lead to an ignition.

Frequency or Trigger

Transmission line switch function testing is conducted on an 8-year cycle. For higher risk switches, both a visual inspection as well as a function exercise will be performed. For lower risk switches, only a visual inspection will be performed.

Accomplishments, Roadblocks, and Updates

PG&E takes an opportunistic approach to bundle switch inspection/function tests to other planned line work clearances. In 2022, coordination was improved, and more inspections were completed compared to the prior year. However, the opportunistic approach still proves challenging as clearances sometimes cannot be extended and resources may not be available to add on this inspection/testing work to existing clearances. For 2023 and beyond, execution of this program will be a hybrid of specifically planned inspection and bundled work where feasible.

8.1.3.1.7 Patrol Inspection

Process

Patrol inspections are defined within the ETPM Manual (TD-1001M) as a brief, visual inspection of applicable utility facilities (equipment and structures) that is designed to identify obvious structural problems and hazards. Patrols are visual reviews of the asset condition to detect imminent or existing safety or reliability hazards. Transmission overhead patrols may be executed on foot or by vehicle based on the terrain.

Frequency or Trigger

Patrols of transmission electric lines and associated equipment are routinely undertaken for assets not scheduled for an enhanced inspection within the calendar year.

Accomplishments, Roadblocks, and Updates

In 2022, patrols were conducted on transmission lines that did not undergo detailed inspection. Inspectors received training with updated job aids to assist with finding asset issues. Going forward, the same approach will be taken, in addition to non-routine patrols after various events like electrical outages or PSPS events. Patrols are currently logged manually to note completion and in 2023 IT solutions are being explored to digitize the patrol process.

8.1.3.1.8 Pilot Inspections

Process

Although most ignition-potential failure modes can be detected through visual inspections, there are some conditions that may not be easily detectable such as conductor degradation, conductor strength, corrosion, wear, annealing, pitting, or below grade foundation condition. Since failure to detect these types of conditions could lead to asset failure PG&E has initiated several additional inspection programs. Many of these programs are in the pilot phase.

- Conductor Measurement/Inspections: This program 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).

- Below Grade Foundation Assessment: This program assesses the condition of the steel structure foundations below the ground line. The inspection includes a measure of soil resistivity, pH, Redox and Half Cell Measurement, as well as visual assessment with photographic evidence of each excavated foundation leg. Cathodic Protection may also be installed concurrently with the inspections.

- Corona Inspections: This program assesses non-visible conditions, particularly of insulator and insulator hardware, by detecting corona (free electrons that fragment stable oxygen molecules (O2) combining with others to create ozone (O3) gases) concentration.

- Ultrasonic Pole Inspection: This pilot program involves a nondestructive test that uses high frequency sound waves to measure the thickness of the metal poles. Measurements will be taken approximately 5 feet from the base of the pole as a baseline, and then again at the ground line to determine any shell thickness loss. It may also be possible to measure the thickness of any protective coating applied to the steel poles which would be helpful to understand the effective period for life extending coatings.

- Corrosion Climbing Assessment: This pilot program involves climbing towers and lattice steel poles to look for evidence of corrosion. This assessment involves scraping/cleaning of existing corrosion control products to see the base metal, assess any crevice corrosion, and assess stub interfaces – removing thick mastic and blisters in paint to fully assess steel, etc. Detailed photos will be taken, including from inside the tower, as part of the inspection process.

- Proactive Sampling and Testing: This program involves taking equipment samples and performing various tests and analyses to understand the overall condition of the asset(s) and factors that promote their failure. 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), size(s) assets from strategic locations on a transmission line circuit for evaluation.

- LiDAR Assessment: This program involves using LiDAR collected on HFTD lines, used in conjunction with Power Line Systems-Computer Aided Drafting and Design models for various engineering analysis such as clearance evaluation and pole loading assessment.

Frequency or trigger

As these programs are in pilot phase, we have not yet developed inspection frequencies. Most, however, have workplans informed by WTRM. Specifically for corona inspections, since they are completed simultaneously with IR inspections, the frequency follows that of IR inspections.

Accomplishments, Roadblocks, and Updates

- In 2022, pilots were conducted for the above-mentioned methodologies. Results will be continuously reviewed as additional inspections are completed in 2023 and beyond. In general, guidance documents need to be developed for pilot maturation. General challenges include providing standardized guidance and questionnaires to capture the information needed from the pilots in a scalable, digitized, and accessible format.

- Specifically for conductor sampling and testing, due to challenges in coordinating sample collection around clearance scheduling, a dedicated program manager is being assigned to this effort in 2023.

Transmission inspection processes are depicted in Figures PG&E-8.1.3-1 and PG&E-8.1.3-2 below.

FIGURE PG&E-8.1.3-1:
TRANSMISSION OVERHEAD ASSET INSPECTION PROCESS

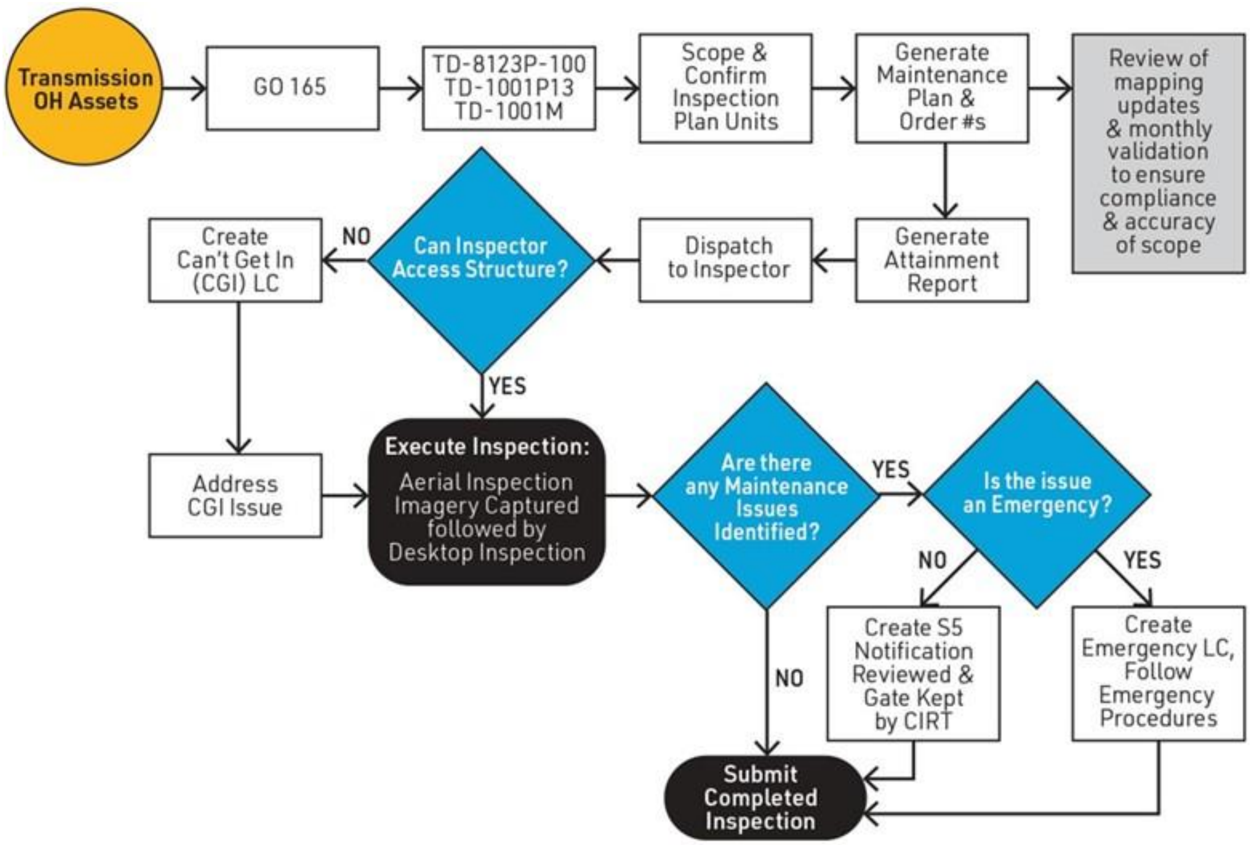
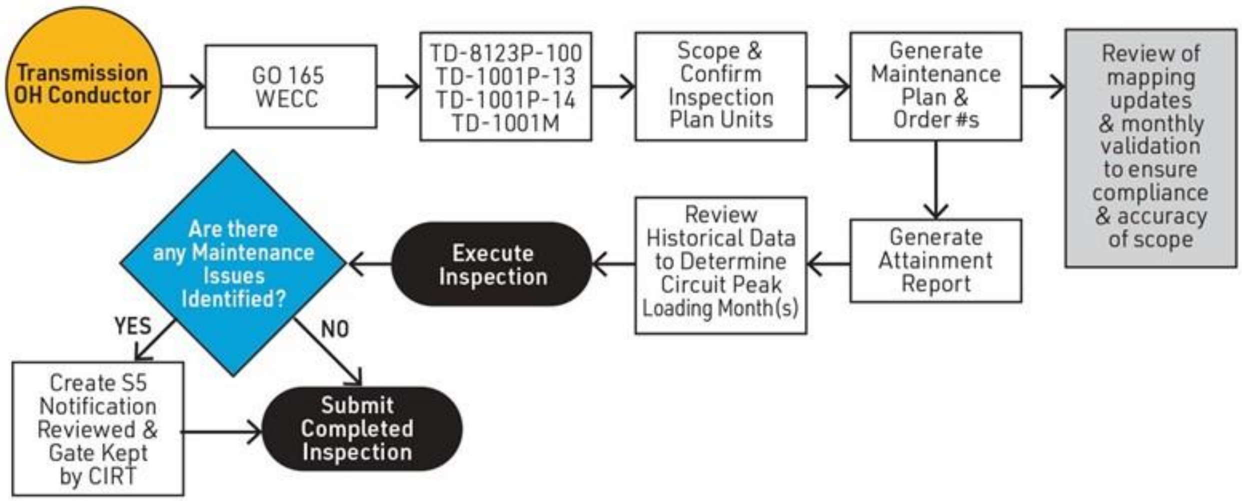


FIGURE PG&E-8.1.3-2:
TRANSMISSION OVERHEAD CONDUCTOR INSPECTION PROCESS



8.1.3.2 Asset Inspections – Distribution

Process

In this section, the electrical corporation must provide an overview of the individual asset inspection program, including inspection criteria and the various inspection methods used for each inspection program.

Include relevant visuals and graphics depicting the workflow and decision-making process the electrical corporation uses for the inspection program.

Frequency or Trigger

In this section, the electrical corporation must identify the frequency (including how frequency may differ by HFTD Tier or other risk designation[s]) or triggers used in the inspection program, such as inputs from the risk model.

If the inspection program is schedule-based, 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.

Accomplishments, Roadblocks, and Updates

In this section, the electrical corporation must discuss:

- *Noteworthy accomplishments for the inspection program since the last WMP;*
- *Roadblocks the electrical corporation has encountered while implementing the inspection program and how the electrical corporation has addressed the roadblocks; and*
- *Changes/updates to the inspection program 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 5 years (i.e., references to and strategies from pilot projects and research).*

Distribution overhead assets in HFTD and HFRA are inspected in accordance with the EDPM Manual. PG&E's methods of inspection include detailed ground inspections, ground patrols, IR inspections, and intrusive pole inspections. In 2023, we will pilot our distribution aerial inspection program at scale, using drones combined with a desktop inspection to identify abnormal conditions. All our inspection programs seek to proactively identify pending failures of asset components, some of which could lead to an ignition. Each inspection type for overhead assets is described below.

Figures PG&E-8.1.3-4 and PG&E-8.1.3-5 at the end of this section depict the Distribution inspection processes.

8.1.3.2.1 Detailed Ground Inspection

Utility Initiative Tracking ID: AI-07

Process

Starting in 2020, PG&E incorporated the enhanced detailed inspection approach used in the Wildlife Safety Inspection Program across our entire Overhead Inspection Program. Enhanced detailed inspections (referred to herein as "detailed inspections") of overhead distribution assets seek to proactively identify areas where we need to conduct corrective work to alleviate imminent equipment failures that could create fire or safety risk. These include abnormal conditions on electric distribution poles, equipment, components, conductors, vegetation, and/or third-party conditions.

Distribution overhead assets in HFTD and HFRA are visually inspected in accordance with GO 165 and with the criteria and guidance set forth in PG&E's EDPM and Overhead Job Aid (TD-2305M-JA02).

Frequency or Trigger

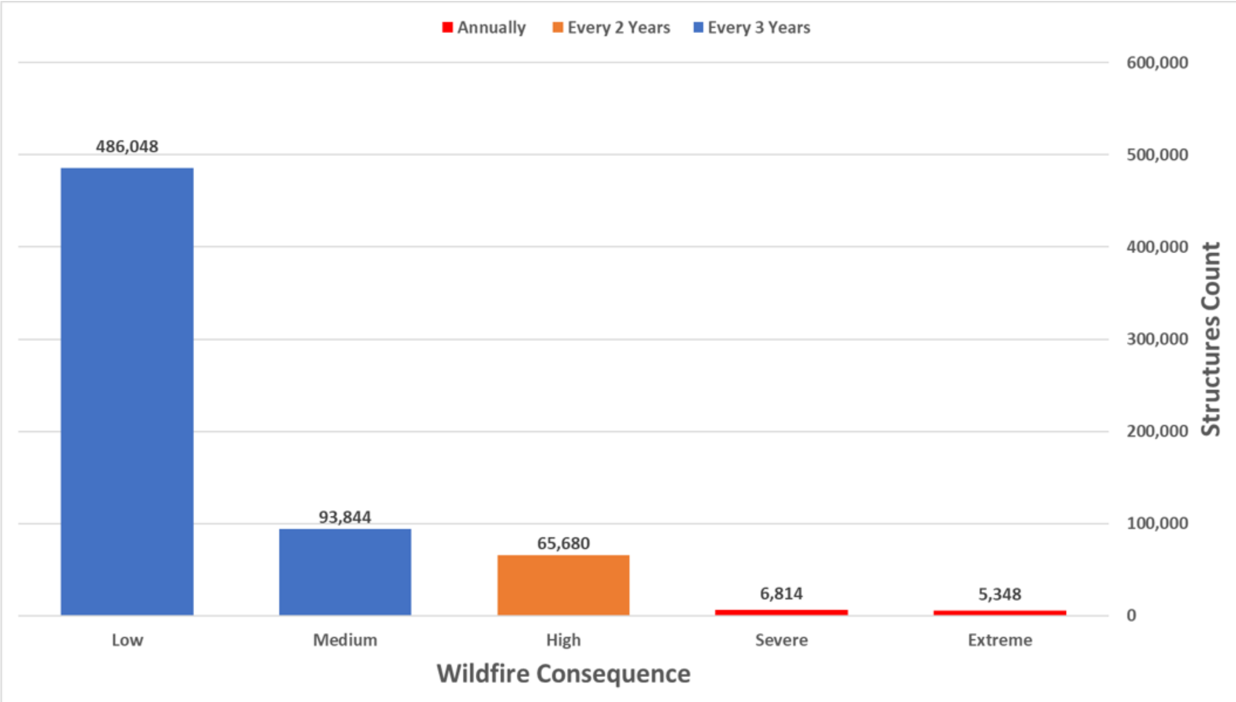
Over the past three years, PG&E has based the frequency of inspection on the HFTD tier in which an asset is located. Support structures in Tier 3 were inspected annually and support structures in Tier 2 were inspected once every three years.

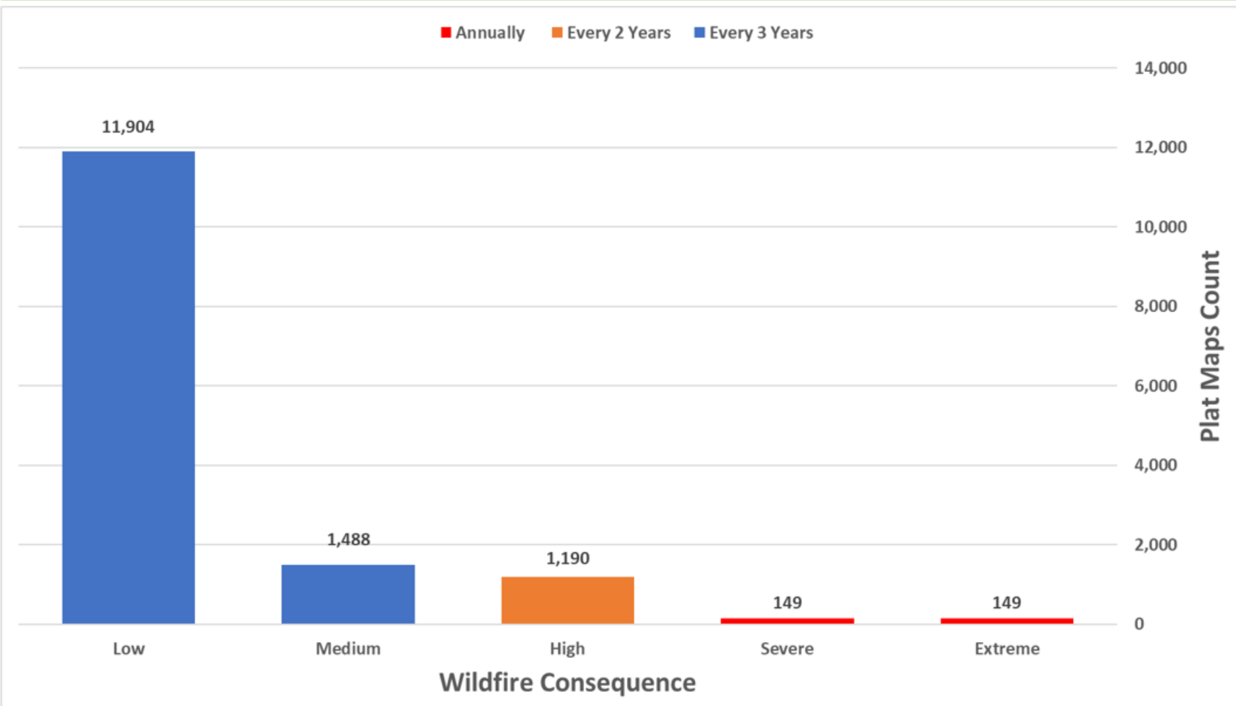
In 2023, PG&E will shift to a detailed inspection strategy that is based on wildfire risk. PG&E's WDRM v3 indicates that the riskiest support structures are found throughout PG&E's high fire areas across Tier 2 and Tier 3, as well as in the HFRA. Because the wildfire risk associated with the support structures in each of these designated areas exhibits a range of values, it makes sense to evolve PG&E's detailed inspection program to be based on the risk of individual structures instead of the tier designation associated with each structure.

To develop the detailed inspection strategy, PG&E aggregated support structures up to the plat map level. The plat map is a geographic unit historically used by inspectors. Completing inspections at the plat map level ensures that inspections are executed efficiently with inspectors completing a set of structures at a given location.

PG&E designated plat maps as extreme, severe, high, medium, or low based on the average wildfire consequence of the structures within that plat map. Figure PG&E-8.1.3-3 shows the count of structures and plat maps assigned to each level of wildfire consequence.

**FIGURE PG&E-8.1.3-3:
ASSIGNING WILDFIRE CONSEQUENCE TO ASSETS AND PLAT MAPS**





PG&E developed a frequency recommendation for each level of consequence: extreme and severe consequence plat maps will be inspected annually; high consequence plat maps will be inspected every other year; and all other plat maps will be inspected once every three years.

We developed our 2023 work plan with the goal of having similar inspection units for the next three years, which would roughly entail inspecting in 2023 all the structures with annual frequencies, half of the plat maps with biannual frequencies, and one-third of all structures with 3-year frequencies. Assembling a work plan in this manner balances the inspection count as well as the levels of risk assessed over the next three years, with roughly 230,000 structures inspected each year.

Finally, PG&E added a limited number of individual structures to the 2023 work plan. These include structures that constitute the top 10 percent of wildfire risk but are not already included in a plat map that is being inspected by ground or aerial; and structures in a plat map that will not be inspected in 2023 but whose inspection frequency would have exceeded three years in 2023. These structures will be inspected individually (separate from the remaining structures in their plat map) in 2023 as an area of concern.

Detailed inspection activities in HFTD and HFRA are scheduled such that extreme, severe, and high consequence plat maps will be completed by July 31. Medium consequence plat maps will be completed by October 1. Low consequence plat maps will be completed by December 31. The detailed schedule for the inspections is developed based on operational field knowledge, coordination with other programs (such as patrols), and constraints, including restricted physical access periods.

Accomplishments, Roadblocks and Updates

In 2022, PG&E completed detailed inspections of 100 percent of our distribution poles in Tier 3 HFTD and Zone 1 areas and 33 percent of the distribution poles in Tier 2 HFTD and HFRA. As of December 31, 2022, a total of 398,539 poles in PG&E's high fire areas were completed. The digital records gathered during detailed inspections have enabled ongoing asset registry improvements.

Specific accomplishments in 2022 include the following:

- Shifting to risk-based inspection frequencies in 2023 instead of inspections based on HFTD Tier. This plan gives us visibility into what structures will be inspected in 2024 and 2025, allowing more time for advanced planning.

- Developing an inspection plan based on plat maps, which will enable efficiencies in execution.

- Updating the inspections checklist and overhead job aid for 2023 to address learnings and emerging issues from 2022.The checklist was also improved to remove redundancies and be more streamlined.

- 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.

- Further improving the monthly inspections validation process to ensure that new poles added to the asset registry are inspected. The process was updated to align with compliance reporting obligations.

One area of focus in 2023 will include coordinating timing of detailed ground inspections with aerial inspections in areas where inspection plans overlap so that tags can be generated in the same time frame.

8.1.3.2.2 Infrared Inspections

Process

Inspecting overhead electric distribution lines and equipment using 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 methods alone.

Frequency or Trigger

PG&E began conducting IR inspections in 2020 on a 3-year cycle in HFTD. In 2021, PG&E leveraged the WDRM v2 consequence to prioritize the HFTD circuit miles selected.

In 2023, PG&E will be deploying IR inspections on an as-needed basis to examine areas of emerging concern. For example, we may deploy IR inspections to complete an extent of condition for a failure that can be detected by IR.

Accomplishments, Roadblocks and Updates

In 2022, the IR Program met its target of inspecting 9,000 miles. The program continued to encounter inspection hurdles such as “cannot get in” (difficult terrain, customer refusals) which required multiple visits to locations.

In 2023, PG&E will be focusing on re-evaluating the role of IR within PG&E’s broader overhead inspections programs as well the standards and processes supporting it. We will consider the effectiveness of this technology compared to other inspection methods and how and when it might be best deployed. Options may include focusing the inspection to detect suspected failure modes on certain structures or components and returning to non-HFTD areas instead of performing inspections in HFTD on a mileage basis.

8.1.3.2.3 Intrusive Pole Inspections

Process

Intrusive pole inspections, also called PT&T, are a way to evaluate in service wood poles for early signs of deterioration. PT&T is a control against premature failure of wood pole structure due to internal rot or shell degradation. The inspection identifies wood poles that are nearing the end of their service life and recommends these poles for replacement or reinforcement prior to failure, which could result in an ignition event. 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. The inspection provides insight into the decay and degradation the poles are experiencing. This helps us to quantify the overall system risk of potential pole failures and informs mitigation plans.

Frequency or Trigger

PG&E currently intrusively inspects wood poles on an approximate 10-year cycle, inspecting roughly 10 percent of the population annually. PG&E is prioritizing intrusive inspection of wood poles based on the time since the previous intrusive inspection. The preservative that PG&E applies during the test lasts for approximately 10 years.

Each pole's inspection cycle is driven by the date of installation into service. GO 165 requires a maximum 20-year cycle for intrusive inspections through the life of the wood pole. PG&E intrusively inspects wood poles approximately every 10-years, based on standard industry practice and the limited efficacy of the preservative treatments. The fact that a pole is in an HFTD or HFRA area is not a factor in the selection of wood poles for intrusive testing. However, enhanced detailed inspections may trigger the need for off-cycle intrusive testing based upon initial visual examination.

In the future, PG&E may develop inspection cycles or triggers that are increasingly risk-based. For example, rather than an approximate 10-year cadence, we may deploy inspections on an as-needed basis using defined criteria. Such an improvement to the existing PT&T program would require extensive analysis before implementation.

Accomplishments, Roadblocks and Updates

While we have not set specific targets for this initiative and will not provide ongoing reporting each quarter, we are still doing intrusive inspections as part of our wildfire mitigation strategy.

In 2023, we plan to perform intrusive pole inspections using enhanced hardware and software, which collects photographs of the poles inspected, including any notable decay or damage. We will adhere to the revised utility procedure (TD-2325P-01) and enhanced testing methods to drill at least one new bore hole when intrusively inspecting wood poles.

In addition, through EPIC 3.46, “Advanced Electric Inspection Tools – Wood Poles,” PG&E is demonstrating a nondestructive testing method, known as Radiographic Testing (RT), to determine whether RT can be used to further analyze the health and condition of wood poles along with identifying any deterioration and degradation that may lead to failure prior to the next scheduled inspection.

8.1.3.2.4 LiDAR-Based Pole Loading Assessments

Process

Determining whether an electric pole is overloaded is an important element in preventing pole failure thereby reducing potential ignition risk. We started our pole loading program by evaluating whether a pole meets GO 95, Rule 44 strength requirements throughout its service life, both when initially installed and while in-service, despite changing conditions, impacts from maintenance activities, attachment additions, and potential wood strength degradation.

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. Pole loading calculations are performed in O-Calc software during design phase to ensure poles are sized correctly to satisfy GO 95 requirements. PG&E created a centralized database to retain pole loading calculation record information in accordance with Decision 09-08-029. Pole loading calculations are based on LiDAR data. LiDAR data is used to accurately locate the pole in relation to surrounding assets, as well as provide measurements for assets attached to the pole (i.e., heights and angles of conductor, clearances between conductors, etc.). LiDAR data allows us to make operational decisions from a desktop, which minimizes field visits and improves efficiency and safety.

Performing pole loading calculations identifies poles that are overloaded which increases the probability of their failing. We also determine where the overloaded poles are located and can compare that to the wildfire ignition consequence profiles which helps us prioritize mitigation efforts.

Frequency or Trigger

The pole loading assessment program is focused on the Tier 2 and 3 HFTD areas with the goal of analyzing 100 percent of poles in these areas by 2024. Poles recently installed, which have recorded pole loading calculations, are not analyzed in this program. The pole loading calculation from the construction package serves as the official record. Poles located in non-HFTD areas will follow, with the goal of analyzing all poles by 2030.

When performing the pole loading calculations, PG&E uses LiDAR data and field collected imagery from the recent system inspections to update the baseline models. PG&E is prioritizing analysis of the poles in the HFTD areas and building the annual plans based on the previous year’s LiDAR and system inspection data captures.

Accomplishments, Roadblocks or Updates

While we have not set specific targets for this Initiative and will not provide ongoing reporting each quarter, we are still doing the work as part of our overall plan.

In 2022, PG&E completed pole loading analysis of more than 314,000 poles, all of which are considered the highest risk poles, either due to the pole characteristics or location, being in an HFTD area.

8.1.3.2.5 Overhead Equipment Inspections

Process

TD-2302P-05 provides Electric Distribution Maintenance Requirements for Miscellaneous Overhead and Underground Equipment outside of GO 165. This utility procedure classifies maintenance tasks for miscellaneous electric overhead and underground equipment, including capacitor banks, fault indicators, interrupters, reclosers, voltage regulators, SCADA, Primary Distribution Alarm and Control controls, and sectionalizers. It 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 hot weather season;
- Testing and ensuring all LR and automatic switches have fully charged batteries and are fully functional; and
- Testing and ensuring all SCADA devices are fully communicating and operable.

Frequency or Trigger

All eligible equipment is inspected every year.

Accomplishments, Roadblocks or Updates

In 2022, PG&E inspected all capacitor banks, reclosers, and regulators in HFTD. PG&E will perform all our miscellaneous overhead inspections in 2023 and beyond as detailed in the Electric Distribution Maintenance Requirements for Miscellaneous Overhead and Underground Equipment Procedure (TD-2302P-05).

8.1.3.2.6 Patrol Inspections

Process

Patrol inspections are a simple, visual examination of applicable overhead and underground facilities to identify obvious structural problems and hazards. Patrol inspections are visual reviews of the asset condition to proactively detect imminent or existing safety or reliability hazards in alignment with GO 165. Distribution overhead patrols may be executed on foot, by vehicle, or by aerial means.

Frequency or Trigger

In 2023, PG&E intends to complete patrol inspections of overhead assets for all HFTD and HFRA assets not being inspected by a detailed ground inspection.

Accomplishments, Roadblocks and Updates

In 2022, PG&E completed a total of 1,330,252 units of patrol in areas not subject to detailed inspections, including in non-HFTD areas. Another accomplishment in 2022 is using two-person crews for patrol in areas that might pose a higher safety risk.

PG&E has not set specific targets for this Initiative and will not provide ongoing reporting each quarter. We will continue to conduct patrols as part of our overall plan.

8.1.3.2.7 Pilot Inspections

Utility Initiative Tracking ID: AI-03

Aerial Inspections

In 2023, PG&E will be piloting a distribution aerial inspections program, testing our ability to scale aerial inspections. We used learnings from our 2022 aerial pilot to design this 2023 pilot inspection program, which consists of a desktop inspection to examine roughly 3-10 photos taken in the field that cover mainly the top one -third of the structure. Drones will be the main vehicle of inspection but other methods such as bucket trucks and handheld cameras will be used as needed to obtain a good aerial view. Discussion of PG&E's 2022 aerial pilot can be found in ACI PG&E-22-20.

2023 will be PG&E's first time implementing aerial inspections at this scale for distribution. While we are not setting a target in this area, we will attempt to complete up to 38,00 inspections by drone in the HFTD/HFRA, more than twelve times the number of inspections we completed by drone-only in 2022 as part of the aerial pilot (3,059 inspections). We will use our learnings from 2023 to develop a procedure for the inspection and to potentially inform future target setting in this area.

Aerial inspections will follow the criteria and guidance set forth in TD-2305M-JA02, the Overhead Job Aid.

Frequency or Trigger

For aerial inspections, PG&E used the same prioritization framework with the same plat map level designation that we used for detailed ground inspections and is described above in the detailed ground inspections section. This framework is based on WDRM v3.0.

In 2023, PG&E will prioritize the new aerial inspections where an ignition would potentially have the greatest consequences which include Extreme, Severe, and High consequence plat maps. We will attempt an aerial inspection for all of the Extreme and Severe plat maps and half of the High consequence plat maps as well, inspecting up to 37,000 structures. Based on 2023 results and learnings, PG&E will develop a more detailed aerial inspections plan for 2024 and 2025 that will incorporate lessons learned from conducting inspections at scale in 2023.

Accomplishments, Roadblocks, and Updates

In 2022, as part of PG&E's follow up on the aerial inspection WMP remedy, PG&E successfully conducted an expanded aerial pilot program on roughly 6,500 structures, exploring three different methods of aerial inspections: drone-only; helicopter-only; and inspector with drone. A detailed discussion of pilot findings and how they were used to develop this pilot aerial inspection program is provided in ACI PG&E-22-20.

In 2023, PG&E will test our ability to execute this type of inspection at larger scale than before. Significant work remains to be done to ensure that tools and processes are in place to enable the scaling of the inspection to hundreds of thousands of units that would be required to cover PG&E's service territory in the near term. The goal of the pilot inspections program in 2023 will be to identify and execute the activities needed to successfully scale the new program. The learnings from 2023 will be used to inform potential future WMP targets in this area.

PG&E's accomplishments in 2022 in the distribution aerial process include the following as part of the pilot.

- Development of a manual process to promptly create corrective maintenance tags from desktop inspections.
- Development of the aerial QC process. This QC process was used to evaluate the preliminary image quality prior to desktop inspections.
- Developing the aerial program using a plat map-based prioritization framework that is consistent with ground inspections. Given that these are complementary inspections, it is reasonable for our overhead inspection strategy to include both inspection types. Using the same underlying risk framework will enable us to plan for ground and aerial inspections in a coordinated fashion in the long term.
- Consolidating guidance for desktop inspectors into the same Overhead Job Aid used by ground inspectors. The Job Aid was also improved to include conditions and examples from aerial inspections, including pictures and a discussion of conditions on cotter keys, tie wires, and other equipment that may be better detected by aerial inspections.

- Improving asset registry data accuracy by providing updates from inspection results when inaccuracies were noted during image capture or desktop inspections.

We are currently conducting other activities in preparation for rolling-out this new inspection program in 2023 including: building an automated process so that tags from desktop inspections are automatically created in SAP rather than having to be manually entered; evaluating whether we can conduct Field Safety Reassessments via aerial inspections for certain open tags; and continuing to evaluate various pilot opportunities within our distribution aerial program.

Figures PG&E-8.1.3-4 and PG&E-8.1.3-5 depict our distribution asset inspection process.

FIGURE PG&E-8.1.3-4:
DISTRIBUTION ASSET INSPECTION PROCESS

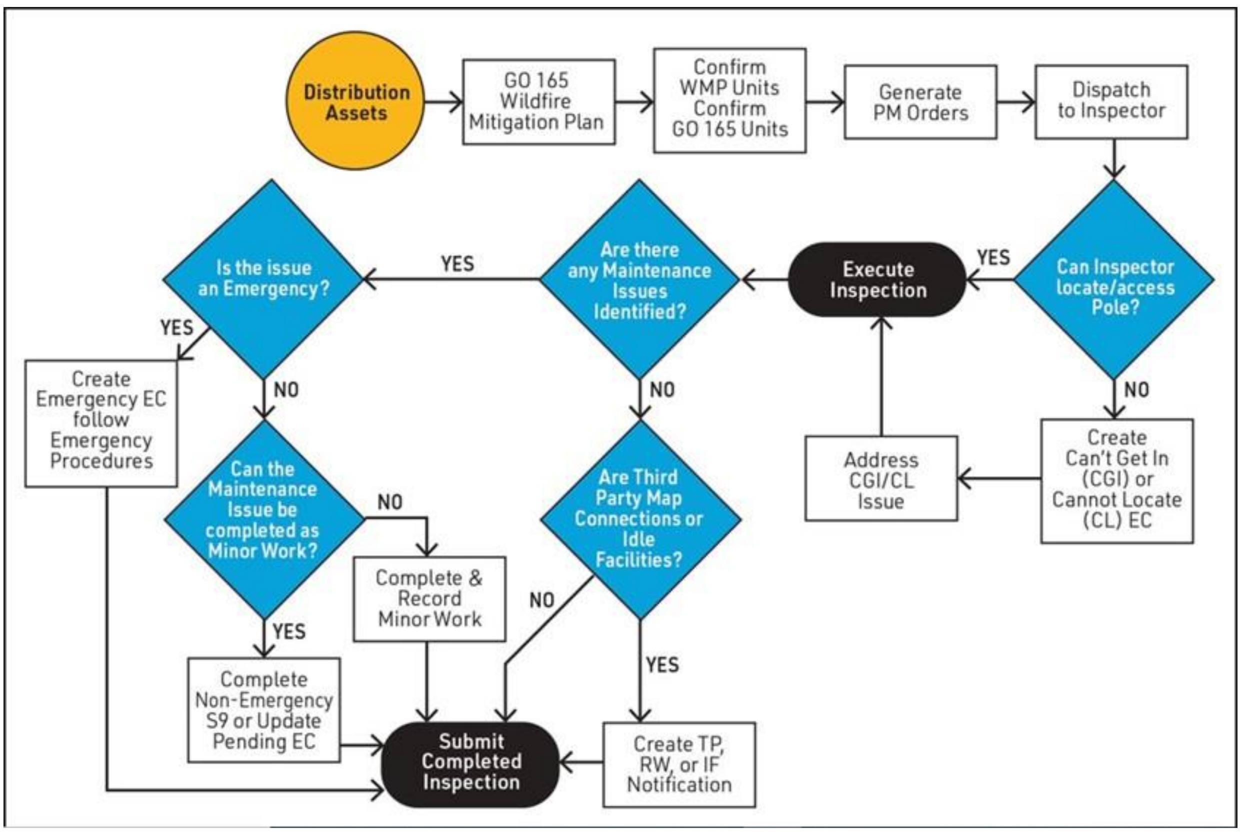
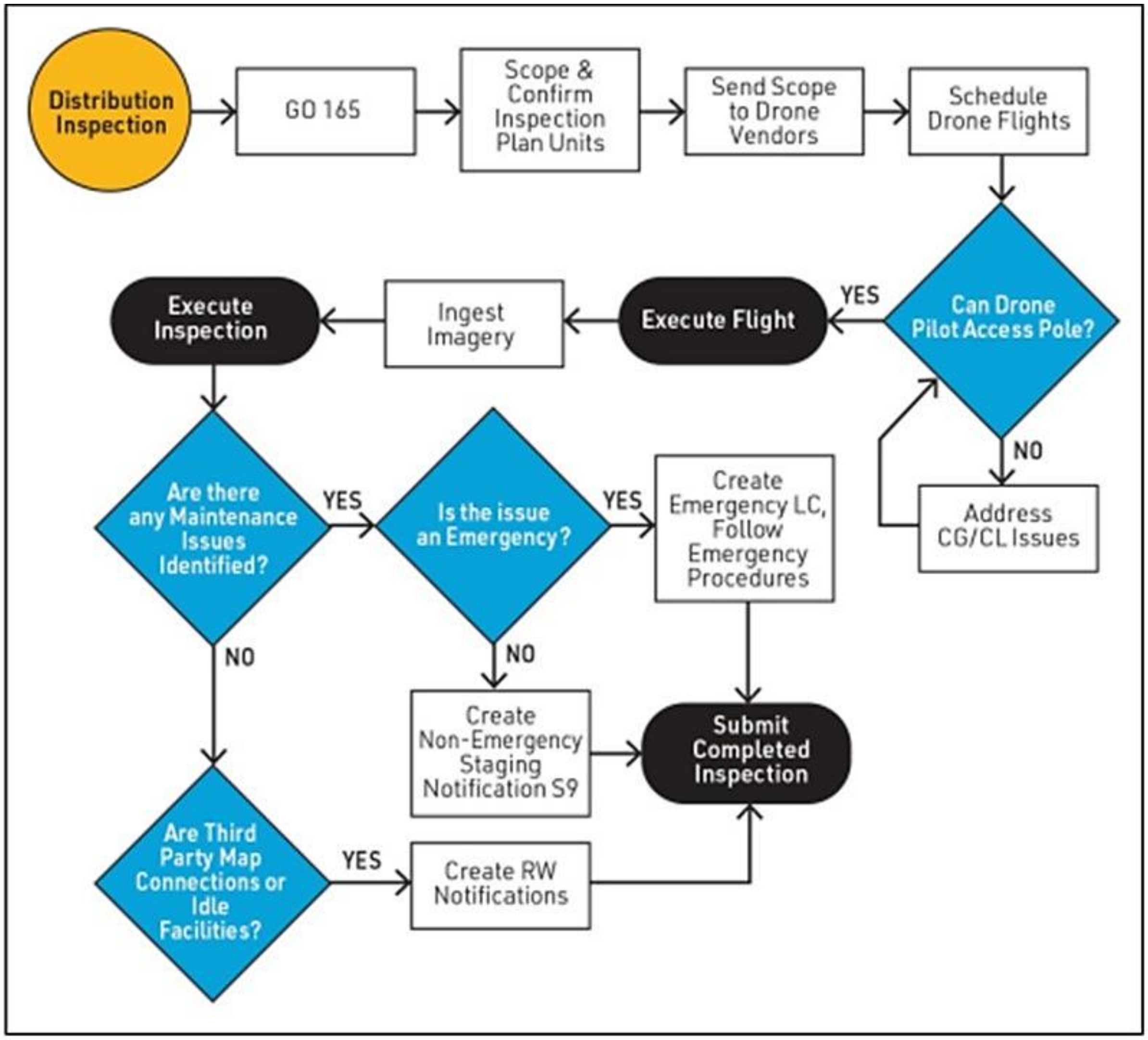


FIGURE PG&E-8.1.3-5:
DISTRIBUTION AERIAL INSPECTION PROCESS



8.1.3.3 Asset Inspections – Substation

Process

In this section, the electrical corporation must provide an overview of the individual asset inspection program, including inspection criteria and the various inspection methods used for each inspection program.

Include relevant visuals and graphics depicting the workflow and decision-making process the electrical corporation uses for the inspection program.

Frequency or Trigger

In this section, the electrical corporation must identify the frequency (including how frequency may differ by HFTD Tier or other risk designation[s]) or triggers used in the inspection program, such as inputs from the risk model.

If the inspection program is schedule-based, 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.

Accomplishments, Roadblocks, and Updates

In this section, the electrical corporation must discuss:

- *Noteworthy accomplishments for the inspection program since the last WMP;*
- *Roadblocks the electrical corporation has encountered while implementing the inspection program and how the electrical corporation has addressed the roadblocks; and*
- *Changes/updates to the inspection program 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 5 years (i.e., references to and strategies from pilot projects and research).*

8.1.3.3.1 Substation Inspections

Utility Initiative Tracking ID: AI-08; AI-09; AI-10

Process

The substation supplemental (enhanced) inspection program is a comprehensive inspection of all the assets inside substations that are located within HFTD and HFRA areas. These inspections are designed to identify equipment issues and damage that may adversely impact reliable operations and/or pose an ignition risk.

Supplemental substation inspections are performed in addition to the routine inspections (GO 174) that are part of the maintenance practices described in PG&E's

Substation Equipment Maintenance Requirements Standard (TD-3322S). The supplemental inspection program includes three methods of inspection: drone-based aerial inspection; ground-based visual inspection; and infrared inspection.

Supplemental inspections are intended to identify ignition risks and equipment conditions requiring repairs or replacements prior to equipment failure. FMEA was performed on all substation equipment and components to identify fire related risks. These inspections are guided by digital checklists that align to the FMEA for substation structures, associated equipment and components. Both objective criteria and SME knowledge are used to evaluate the condition of the assets and identify corrective actions. The information gathered from supplemental inspections may inform new programmatic responses including equipment replacements, improvements to maintenance policies, changes in the frequency of maintenance, or guidance clarifications.

Figure PG&E-8.1.3-6 below is a diagram depicting the substation inspection process.

Frequency or Trigger

In general, PG&E schedules patrol and supplemental inspection activities in HFTD areas earlier in the year to provide time for necessary repairs prior to peak fire season.

Supplemental substation inspections are planned on a 3-year baseline cycle for all stations located within HFTD and HFRA areas and documented within Utility Standards TD-3328S and TD-8124S. A portion of the substations are pulled into the in-year inspection plan are based on a risk matrix that includes defensible space completion status to determine probability (described in Section 8.2.3.5) and the Wildfire Consequence Model to determine consequence. The probability and consequence scores are then combined into a nine-box matrix to determine the final risk level; High, Medium, or Low. High Risk and Medium Risk substations are inspected more frequently by advancing them from the 3-year baseline inspection cycle to the in-year inspection plan while Low Risk substations remain on the 3-year baseline inspection cycle. The inspection criteria and the development of the inspections plan are documented in Utility Procedure TD-3328P-01.

Substation currently uses two independent ground-based visual inspection programs: (1) routine based general visual substation inspections performed on a monthly or bi-monthly basis; and (2) supplemental wildfire ground based visual inspections performed on a 3-year baseline cycle with some stations performed in-year based on risk. PG&E is developing plans to optimize our approach to ground–based inspections by combining or optimizing certain functions of the programs for 2024 and beyond.

PG&E's substation inspection targets are shown in Table PG&E-8.1.3-1 below.

TABLE PG&E-8.1.3-1:
SUBSTATION INSPECTION TARGETS

Substation Supplemental Inspections			
	2023	**2024**	**2025**
Transmission Substation	34	36	41
Distribution Substation	52	76	78
Hydro Generation Substation	41	46	40
Total:	127	158	159

Accomplishments, Roadblocks or Updates

Roadblocks

In 2022, the substation supplemental inspections program encountered challenges with contractors who historically performed ground based supplemental inspections. PG&E pivoted the work to be performed by internal substation personnel.

Accomplishments

Because of contractor challenges for the ground based supplemental inspections program in 2022, PG&E began to use internal personnel to perform ground-based substation supplemental inspections. An associated quality review process was also implemented to evaluate the effectiveness of using our internal resources to conduct these inspections with successful results. In 2023 and beyond, PG&E intends to continue with this execution plan and will implement additional QC and QA reviews over the substation inspection execution process.

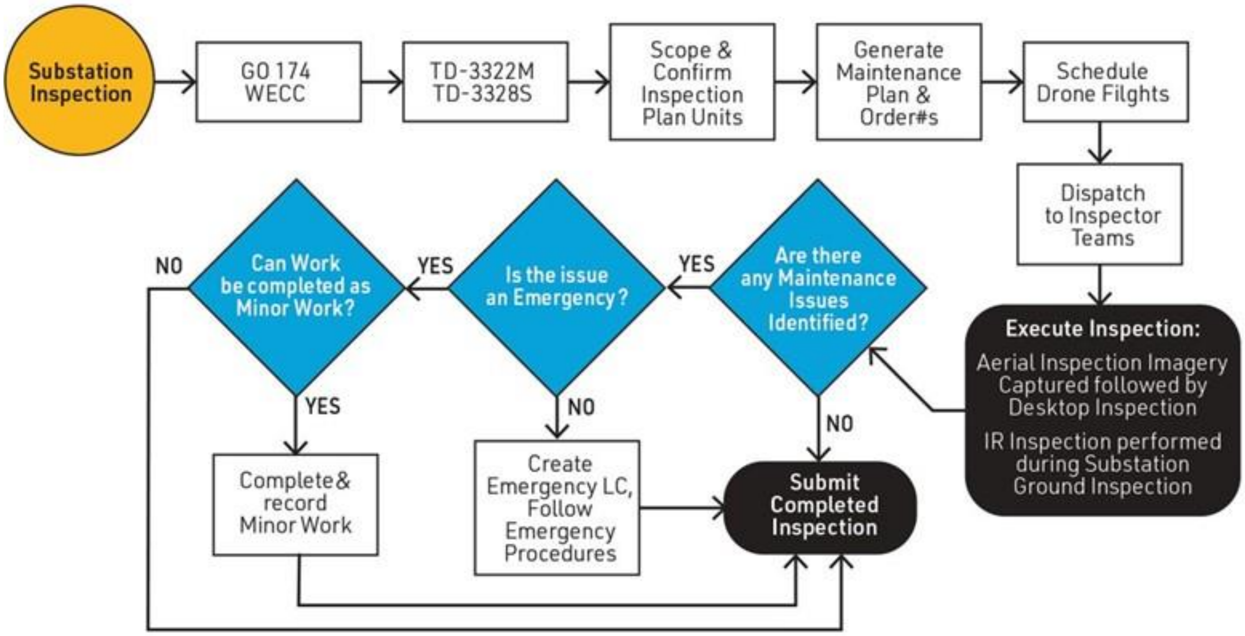
In addition, through EPIC 3.41, "Drone Enablement", PG&E is demonstrating BVLOS drone-based asset inspection capabilities, which includes the exploration and advancement of autonomous substation inspections.

Updates

PG&E's Power Generation organization performs supplemental inspections that align with Electric Operations substation procedures at all Power Generation substations. Routine inspections for Power Generation substations fall under Federal Energy Regulatory Commission jurisdiction and are not regulated by GO 174 commitments. To further mitigate wildfire, safety and reliability risks and more closely align with Substation routine inspections, Power Generation implemented a routine inspection program beginning in 2022 with plans to incrementally develop and mature the program over time. Beginning in 2024, Power Generation plans to establish an internal inspection team to support both routine and supplemental inspections for Power Generation substations.

Figure PG&E-8.1.3-6 depicts PG&E's substation inspection process.

FIGURE PG&E-8.1.3-6:
SUBSTATION INSPECTION PROCESS



8.1.4 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 programs. 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:

- *Capacitors;*
- *Circuit breakers;*
- *Connectors, including hotline clamps;*
- *Conductor, including Covered Conductor (CC);*
- *Fuses, including expulsion fuses;*
- *Distribution poles;*
- *Lightning arrestors;*
- *Reclosers;*
- *Splices;*
- *Transmission poles/towers;*
- *Transformers; and*
- *Other equipment not listed.*

For the equipment maintenance and repair listed in the subsections below, we understand proactive maintenance to mean that a targeted program is in place to actively address risk before it is realized or identifying risk condition(s) and addressing the condition(s) before failure.

8.1.4.1 Capacitors Maintenance

The electrical corporation must provide a brief narrative of maintenance programs. This 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.

Relevant Asset Types (Select all that apply)

Distribution ☒	Transmission ☐	Substation ☐

Asset Maintenance Programs (Select all that apply)

Proactive ☒	**Reactive ☐**
Targeted program in place to actively address risk before it is realized, or identification of conditions and addressing the condition before failure.	Replacement or repair of component after failure.

Program Descriptions

Please briefly describe any programs checked above. Responses should include:

- *Any timing or triggering events for maintenance;*

All distribution capacitors are annually inspected as part of the Distribution Overhead Equipment Inspection Program. The procedure is described in Section 8.1.3.2. The annual inspections and testing are completed before the peak load season starts.

- *Prioritization methodologies or approaches;*

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.

- *Primary activities to address the identified issues with the asset (e.g., removal, replacement, repair, etc.); and*

N/A – Covered in Prioritization, Methodologies, or Approaches section above.

- *Planned changes to the asset maintenance program from 2023-2025.*

N/A – No planned changes.

8.1.4.2 Circuit Breakers Maintenance

The electrical corporation must provide a brief narrative of maintenance programs. This 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.

Equipment Name	Circuit Breakers	**Section Number**	

Relevant Asset Types (Select all that apply)

Distribution ☐	**Transmission ☐**	**Substation ☒**

Asset Maintenance Programs (Select all that apply)

Proactive ☒ Targeted program in place to actively address risk before it is realized, or identification of conditions and addressing the condition before failure.	**Reactive ☐** Replacement or repair of component after failure.

Program Descriptions

Please briefly describe any programs checked above. Responses should include:

- *Any timing or triggering events for maintenance;*

Substation circuit breakers are maintained in accordance with Utility Standard Substation Equipment Maintenance Requirements (TD-3322S, Attachment 7),[128] which includes provisions for preventive time based and condition-based maintenance. Requisite maintenance tasks include mechanism service and 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, substation time-based maintenance task intervals can vary from annual, bi-annual, 4 years, 8 years, or 12 years, based on circuit breaker type and application. Since the program uses some condition-based triggers—such as oil sample results—in addition to time-based intervals—such as mechanism service and exercise—to initiate maintenance tasks, the intervals are not always linear and the frequencies between maintenance tasks may vary.

- *Prioritization methodologies or approaches;*

Substation circuit breaker maintenance tasks are prioritized based on cyclical time triggers and actual equipment condition. The replacement programs apply to all

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substation circuit breakers and are replaced using one of the four replacement mechanisms: prioritization model driven replacement; emergency failure; Just-in-Time (JIT) replacement; and capacity driven replacements.

As part of Enhanced Power Line Safety Setting (EPSS) Program, PG&E identified instances of circuit breaker incompatibility with the EPSS relaying devices. This triggered circuit breaker replacements in 2022 to conform with EPSS Program needs. In 2023 and 2024, PG&E will continue to replace additional distribution circuit breakers for similar purposes and will look for opportunities to replace circuit breakers in 2025 and beyond. These circuit breaker replacements are necessary when older styles of circuit breakers are not compatible with modern microprocessor relays such as those used with EPSS schemes.

- *Primary activities to address the identified issues with the asset (e.g., removal, replacement, repair, etc.); and*

PG&E's substation circuit breaker maintenance and replacement program ensures that circuit breakers are properly installed and maintained to prevent operational failures. A circuit breaker failure could result in an increased risk of ignition, as improper 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. Beginning in 2024, PG&E plans to add the Wildfire Distribution Risk Model to the circuit breaker replacement prioritization model. Power Generation aligns to a similar proactive replacement strategy for 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 due to the small asset inventory and low number of occurrences.

- *Planned changes to the asset maintenance program from 2023-2025.*

N/A – No anticipated changes.

8.1.4.3 Connectors Maintenance (Including Hotline Clamps)

The electrical corporation must provide a brief narrative of maintenance programs. This 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.

Equipment Name	Connectors Maintenance (Including Hotline Clamps)	**Section Number**	

Relevant Asset Types (Select all that apply)

Distribution ☒	**Transmission ☐**	**Substation ☐**

Asset Maintenance Programs (Select all that apply)

Proactive ☒	**Reactive ☐**
Targeted program in place to actively address risk before it is realized, or identification of conditions and addressing the condition before failure.	Replacement or repair of component after failure.

Program Descriptions

Please briefly describe any programs checked above. Responses should include:

- *Any timing or triggering events for maintenance;*

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 8.1.3.2. 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).

- *Prioritization methodologies or approaches;*

Connector issues are fixed by replacing the connector. The findings are addressed in a risk prioritized manner as described in Section 8.1.7.2 through the Electric Corrective (EC) tag process.

- *Primary activities to address the identified issues with the asset (e.g., removal, replacement, repair, etc.); and*

N/A – Covered in Prioritization, Methodologies or Approaches section above.

- *Planned changes to the asset maintenance program from 2023-2025.*

N/A – No planned changes.

Equipment Name	Transmission Connector	**Section Number**	

Relevant Asset Types (Select all that apply)

Distribution ☐	**Transmission ☒**	**Substation ☐**

Asset Maintenance Programs (Select all that apply)

Proactive ☒ Targeted program in place to actively address risk before it is realized, or identification of conditions and addressing the condition before failure.	**Reactive ☐** Replacement or repair of component after failure.

Program Descriptions

Please briefly describe any programs checked above. Responses should include:

- *Any timing or triggering events for maintenance;*

Maintenance of transmission connectors is typically triggered via detailed overhead inspections and patrol. Detailed overhead inspections are both risk and compliance driven, performed as described in Section 8.1.3.1. Connector findings may result in replacement or repair. Inspections that address connector concerns include detailed ground, detailed aerial, climbing, and infrared/corona. Extent of condition assessment may be triggered by specific conditions identified.

- *Prioritization methodologies or approaches;*

Maintenance on connectors is mainly driven by inspection findings, which is prioritized as described in Section 8.1.7.1. Maintenance on connectors can occur during inspection findings or through engineering assessment.

- *Primary activities to address the identified issues with the asset (e.g., removal, replacement, repair, etc.); and*

Typically, maintenance activities include repair, replacement, or removal. The maintenance activity is determined using the Electric Transmission Preventative Maintenance (ETPM), job aids, and applicable standards.

- *Planned changes to the asset maintenance program from 2023-2025.*

Sampling and testing conducted during this period will inform future maintenance requirements.

8.1.4.4 Conductors (Including CCs)

The electrical corporation must provide a brief narrative of maintenance programs. This 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.

Equipment Name	Distribution Conductors (including CCs)	**Section Number**	

Relevant Asset Types (Select all that apply)

Distribution ☒	**Transmission ☐**	**Substation ☐**

Asset Maintenance Programs (Select all that apply)

Proactive ☒	**Reactive ☐**
Targeted program in place to actively address risk before it is realized, or identification of conditions and addressing the condition before failure.	Replacement or repair of component after failure.

Program Descriptions

Please briefly describe any programs checked above. Responses should include:

- *Any timing or triggering events for maintenance;*

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 8.1.3.2. Some of the conductor conditions that are monitored include broken/damaged, burnt, corroded, loose, frayed or bird caging, missing covers for CCs, and clearance. A full list of conditions that are monitored are in the PG&E Overhead Inspection Job Aid (TD-2305M-JA02).

- *Prioritization methodologies or approaches;*

Conductor issues are fixed by replacing or repairing the conductor. The findings are addressed in a risk prioritized manner as described in Section 8.1.7.2 through the EC tag process.

- *Primary activities to address the identified issues with the asset (e.g., removal, replacement, repair, etc.); and*

N/A – Covered in Prioritization, Methodologies or Approaches section above.

- *Planned changes to the asset maintenance program from 2023-2025.*

In 2022, the joint IOUs continued to work on the joint CC effectiveness study to better understand the advantages, operative failure modes, and current state of knowledge regarding CCs. As part of the joint IOU work, testing of CCs was conducted and a final report is expected in February 2023. PG&E will continue to review the findings from the study and evaluate changes that are necessary to the inspection of CCs. See ACI PG&E-22-11.

Equipment Name	Transmission Conductors	Section Number	

Relevant Asset Types (Select all that apply)

Distribution ☐	Transmission ☒	Substation ☐

Asset Maintenance Programs (Select all that apply)

Proactive ☒	Reactive ☐
Targeted program in place to actively address risk before it is realized, or identification of conditions and addressing the condition before failure.	Replacement or repair of component after failure.

Program Descriptions

Please briefly describe any programs checked above. Responses should include:

- *Any timing or triggering events for maintenance;*

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 8.1.3.1. Conductor findings may result in replacement or repair. Inspections related to conductors include detailed ground, detailed aerial, infrared/corona, and pilot programs including conductor measurement, sampling, and testing.

- *Prioritization methodologies or approaches;*

Maintenance on conductors is mainly driven by inspection findings, which are prioritized as described in Section 8.1.7.1. Maintenance on conductors can occur because of inspection findings or with input from an engineering assessment.

- *Primary activities to address the identified issues with the asset (e.g., removal, replacement, repair, etc.); and*

Typically, maintenance activities include repair, replacement, or removal. The maintenance activity is determined using the ETPM, job aids, and applicable standards.

- *Planned changes to the asset maintenance program from 2023-2025.*

Pilot inspection, sampling, and testing conducted during this period will inform future maintenance requirements.

8.1.4.5 Fuses (Including Expulsion Fuses)

The electrical corporation must provide a brief narrative of maintenance programs. This 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.

Equipment Name	Fuses (including expulsion fuses)	**Section Number**	

Relevant Asset Types (Select all that apply)

Distribution ☒	**Transmission** ☐	**Substation** ☐

Asset Maintenance Programs (Select all that apply)

Proactive ☒	**Reactive** ☐
Targeted program in place to actively address risk before it is realized, or identification of conditions and addressing the condition before failure.	Replacement or repair of component after failure.

Program Descriptions

Please briefly describe any programs checked above. Responses should include:

- *Any timing or triggering events for maintenance;*

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 8.1.3.2. 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).

In addition, PG&E performs infrared detailed overhead inspections of distribution electric lines and equipment in the HFTD (Section 8.1.3.2) 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.

Furthermore, we are proactively removing and/or replacing non-exempt expulsion fuses in the High Fire Risk Area (HFRA) to mitigate wildfire risk, as discussed in Section 8.1.2.10.5.

- *Prioritization methodologies or approaches;*

The issues found through the inspection programs are addressed in a risk prioritized manner as described in Section 8.1.7.2 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.

- *Primary activities to address the identified issues with the asset (e.g., removal, replacement, repair, etc.); and*

N/A – Covered in Prioritization, Methodologies or Approaches section above.

- *Planned changes to the asset maintenance program from 2023-2025.*

N/A – No planned changes.

8.1.4.6 Distribution Poles

The electrical corporation must provide a brief narrative of maintenance programs. This 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.

Equipment Name	Distribution Poles	**Section Number**	

Relevant Asset Types (Select all that apply)

Distribution ☒	**Transmission ☐**	**Substation ☐**

Asset Maintenance Programs (Select all that apply)

Proactive ☒ Targeted program in place to actively address risk before it is realized, or identification of conditions and addressing the condition before failure.	**Reactive ☐** Replacement or repair of component after failure.

Program Descriptions

Please briefly describe any programs checked above. Responses should include:

- *Any timing or triggering events for maintenance;*

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 Pole Test and Treat (PT&T) Program. Inspections are both risk and compliance driven and are performed as described in Section 8.1.3.2. 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.

Also included are poles that are identified as potentially overloaded through system inspections or the pole loading assessment as described in Section 8.1.3.2.

- *Prioritization methodologies or approaches;*

Pole issues, including overloaded poles, are fixed by replacing or stubbing the pole. The findings are addressed in a risk prioritized manner as described in Section 8.1.7.2 through the EC tag process.

- *Primary activities to address the identified issues with the asset (e.g., removal, replacement, repair, etc.); and*

N/A – Covered in Prioritization, Methodologies, or Approaches section above.

- *Planned changes to the asset maintenance program from 2023-2025.*

N/A – No planned changes.

8.1.4.7 Lightning Arrestors

The electrical corporation must provide a brief narrative of maintenance programs. This 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.

Equipment Name	Lightning Arrestor	**Section Number**	

Relevant Asset Types (Select all that apply)

Distribution ☒	**Transmission ☐**	**Substation ☐**

Asset Maintenance Programs (Select all that apply)

Proactive ☒ Targeted program in place to actively address risk before it is realized, or identification of conditions and addressing the condition before failure.	**Reactive ☐** Replacement or repair of component after failure.

Program Descriptions

Please briefly describe any programs checked above. Responses should include:

- *Any timing or triggering events for maintenance;*

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 8.1.3.2. 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).

In addition, PG&E is proactively removing or replacing non-exempt lightning arresters with grounding issues located in HFTD and HFRA. For more details about this program, see Section 8.1.2.10.4.

- *Prioritization methodologies or approaches;*

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 8.1.7.2 through the EC tag process.

The proactive replacement program is targeting the replacement of known non-exempt surge arrester locations in HFTD and HFRA with potentially deficient grounding. PG&E expects to complete the program by 2025, barring external factors such as access issues.

- *Primary activities to address the identified issues with the asset (e.g., removal, replacement, repair, etc.); and*

N/A – Covered in Prioritization, Methodologies, or Approaches section above.

- *Planned changes to the asset maintenance program from 2023-2025.*

N/A – No planned changes.

8.1.4.8 Reclosers

The electrical corporation must provide a brief narrative of maintenance programs. This 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.

Equipment Name	Reclosers	**Section Number**	

Relevant Asset Types (Select all that apply)

Distribution ☒	**Transmission ☐**	**Substation ☐**

Asset Maintenance Programs (Select all that apply)

Proactive ☒	**Reactive ☐**
Targeted program in place to actively address risk before it is realized, or identification of conditions and addressing the condition before failure.	Replacement or repair of component after failure.

Program Descriptions

Please briefly describe any programs checked above. Responses should include:

- *Any timing or triggering events for maintenance;*

All distribution reclosers are annually inspected as part of the Distribution Overhead Equipment Inspection Program. The procedure is described in Section 8.1.3.2.

- *Prioritization methodologies or approaches;*

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.

- *Primary activities to address the identified issues with the asset (e.g., removal, replacement, repair, etc.); and*

N/A – Covered in Prioritization, Methodologies, or Approaches section above.

- *Planned changes to the asset maintenance program from 2023-2025.*

N/A – No planned changes.

8.1.4.9 Splices

The electrical corporation must provide a brief narrative of maintenance programs. This 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.

Equipment Name	Distribution Splices	**Section Number**	

Relevant Asset Types (Select all that apply)

Distribution ☒	**Transmission ☐**	**Substation ☐**

Asset Maintenance Programs (Select all that apply)

Proactive ☒	**Reactive ☐**
Targeted program in place to actively address risk before it is realized, or identification of conditions and addressing the condition before failure.	Replacement or repair of component after failure.

Program Descriptions

Please briefly describe any programs checked above. Responses should include:

- *Any timing or triggering events for maintenance;*

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 8.1.3.2. Some of the splice 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).

- *Prioritization methodologies or approaches;*

Splice issues are fixed by replacing the splice. The findings are addressed in a risk prioritized manner as described in Section 8.1.7.2 through the EC tag process.

- *Primary activities to address the identified issues with the asset (e.g., removal, replacement, repair, etc.); and*

N/A – Covered in Prioritization, Methodologies or Approaches section above.

- *Planned changes to the asset maintenance program from 2023-2025.*

N/A – No planned changes.

Equipment Name	Transmission Splices	Section Number	

Relevant Asset Types (Select all that apply)

Distribution ☐	Transmission ☒	Substation ☐

Asset Maintenance Programs (Select all that apply)

Proactive ☒	**Reactive ☐**
Targeted program in place to actively address risk before it is realized, or identification of conditions and addressing the condition before failure.	Replacement or repair of component after failure.

Program Descriptions

Please briefly describe any programs checked above. Responses should include:

- *Any timing or triggering events for maintenance;*

Transmission splice maintenance is primarily identified through detailed overhead inspections and patrols. Inspections specific to addressing splices include detailed ground, detailed aerial, and infrared/corona. 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.

- *Prioritization methodologies or approaches;*

Maintenance on splices is mainly driven by inspection findings, which is prioritized as described in Section 8.1.7.1. Maintenance on splices can occur during detailed overhead inspections or have with input from an engineering assessment.

- *Primary activities to address the identified issues with the asset (e.g., removal, replacement, repair, etc.); and*

Typically, maintenance activities include repair, replacement, or removal. The maintenance activity is determined using the ETPM, job aids, and applicable standards.

- *Planned changes to the asset maintenance program from 2023-2025.*

From 2023-2025, transmission lines will be targeted for shunt splice installation (See target GH-05 in Section 8.1.1.2). Additionally, sampling and testing conducted during this period will inform future maintenance requirements.

8.1.4.10 Transmission Poles/Towers

The electrical corporation must provide a brief narrative of maintenance programs. This 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.

Equipment Name	Transmission Poles/Towers	**Section Number**	

Relevant Asset Types (Select all that apply)

Distribution ☐	**Transmission ☒**	**Substation ☐**

Asset Maintenance Programs (Select all that apply)

Proactive ☒ Targeted program in place to actively address risk before it is realized, or identification of conditions and addressing the condition before failure.	**Reactive ☐** Replacement or repair of component after failure.

Program Descriptions

Please briefly describe any programs checked above. Responses should include:

- *Any timing or triggering events for maintenance;*

Transmission poles and tower maintenance is primarily identified through inspections and patrols including detailed ground, detailed aerial, climbing, intrusive pole inspection, and pilot inspections such as below grade assessment and ultrasonic pole inspection.

- *Prioritization methodologies or approaches;*

Maintenance on poles is mainly driven by inspection findings, which is prioritized as described in Section 8.1.7.1. Maintenance on towers can occur during inspections or with input from an engineering assessment.

- *Primary activities to address the identified issues with the asset (e.g., removal, replacement, repair, etc.); and*

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 the ETPM, job aids, and applicable standards.

- *Planned changes to the asset maintenance program from 2023-2025.*

Updates to the wood pole procedure is expected between 2023 and 2025. Pilot inspections, sampling, and testing from 2023 to 2025 will inform future maintenance requirements.

8.1.4.11 Transformers

The electrical corporation must provide a brief narrative of maintenance programs. This 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.

Equipment Name	Distribution Overhead Transformers	**Section Number**	

Relevant Asset Types (Select all that apply)

Distribution ☒	**Transmission ☐**	**Substation ☐**

Asset Maintenance Programs (Select all that apply)

Proactive ☒ Targeted program in place to actively address risk before it is realized, or identification of conditions and addressing the condition before failure.	**Reactive ☐** Replacement or repair of component after failure.

Program Descriptions

Please briefly describe any programs checked above. Responses should include:

- *Any timing or triggering events for maintenance;*

Distribution overhead transformers are partly proactively managed and generally run to condition. Detailed overhead inspections are both risk and compliance driven, performed per Section 8.1.3.2, 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 8.1.7.2. 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. Some of the transformer conditions that are monitored include corrosion, physical damage, and leaking oil. A full list of conditions that are monitored are defined in the PG&E Overhead Inspection Job Aid (TD-2305M-JA02).

- *Prioritization methodologies or approaches;*

Transformer issues are fixed by replacing the transformer. The findings are addressed in a risk prioritized manner as described in Section 8.1.7.2 through the EC tag process.

- *Primary activities to address the identified issues with the asset (e.g., removal, replacement, repair, etc.); and*

N/A – Covered in Prioritization, Methodologies, or Approaches section above.

- *Planned changes to the asset maintenance program from 2023-2025.*

Through our Electric Program Investment Charge (EPIC) 3.20 "Maintenance Analytics" project, PG&E has developed an analytical model that leverages SmartMeter™ data to identify transformers that have a high likelihood of failure. Based on continued testing and validation of the model, we may expand proactive transformer replacement and instead replace the highest risk transformers (high likelihood of failure and located in high wildfire consequence geo locations).

In addition, through our EPIC 3.13 "Transformer Monitoring via Field Area Network (FAN)" project, PG&E is demonstrating a transformer temperature monitoring system that includes transformer predictive failure analytics using transformer temperature data over time.

8.1.4.12 Other Equipment Not Listed

The electrical corporation must provide a brief narrative of maintenance programs. This 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.

Equipment Name	Transmission Line Switches	**Section Number**	

Relevant Asset Types (Select all that apply)

Distribution ☐	**Transmission ☒**	**Substation ☐**

Asset Maintenance Programs (Select all that apply)

Proactive ☒	**Reactive ☐**
Targeted program in place to actively address risk before it is realized, or identification of conditions and addressing the condition before failure.	Replacement or repair of component after failure.

Program Descriptions

Please briefly describe any programs checked above. Responses should include:

- *Any timing or triggering events for maintenance;*

Transmission switch maintenance is primarily identified through inspections and patrols including detailed ground, detailed aerial, infrared/corona, and switch function testing.

- *Prioritization methodologies or approaches;*

Maintenance on switches is mainly driven by inspection findings, which is prioritized as described in Section 8.1.7.1. Maintenance on switches can occur during inspections or with input from an engineering assessment.

- *Primary activities to address the identified issues with the asset (e.g., removal, replacement, repair, etc.); and*

Typically, maintenance activities include repair, replacement, or removal. The maintenance activity is determined using the ETPM, job aids, and applicable standards.

- *Planned changes to the asset maintenance program from 2023-2025.*

Switch function testing, sampling, and testing is expected from 2023 to 2025 to inform future switch maintenance.

8.1.5 Asset Management and Inspection Enterprise System(s)

In this section, the electrical corporation must provide an overview of Inputs, operation, and support for centralized asset management and inspection enterprise system(s) updated based upon inspection results and activities such as hardening, maintenance, and remedial work. This overview must include discussion of:

- *The electrical corporation's asset inventory and condition database;*
- *Describe the electrical corporation's internal documentation of its database(s);*
- *Integration with systems in other lines of business;*
- *Integration with the auditing system(s) (see Quality Assurance/Quality Control (QA/QC) section below);*
- *Describe internal procedures for updating the enterprise system including database(s) and any planned updates; and*
- *Any changes to the initiative since the last Wildfire Mitigation Plan (WMP) submission and a brief explanation as to why those changes were made. Include any planned improvements or updates to the initiative and the timeline for implementation.*

Utility Initiative Tracking ID: AI-11

The Electrical Corporation's Asset Inventory and Condition Database

PG&E has significantly advanced our data management practices and the quality of our asset inventory (Asset Registry) database over the last two years by applying the International Organization for Standardization (ISO) 55001 standards (see Appendix E), deploying data management and governance standards and processes, and implementing projects and programs to close major data quality gaps. These efforts focus on improving the quality and timeliness of new data being entered into our asset inventory database, as well as addressing gaps in the quality of historical asset data. Further definition and details of these programs and projects is provided in ACI PG&E-22-33 Progress on Filling Asset Inventory Data Gaps.

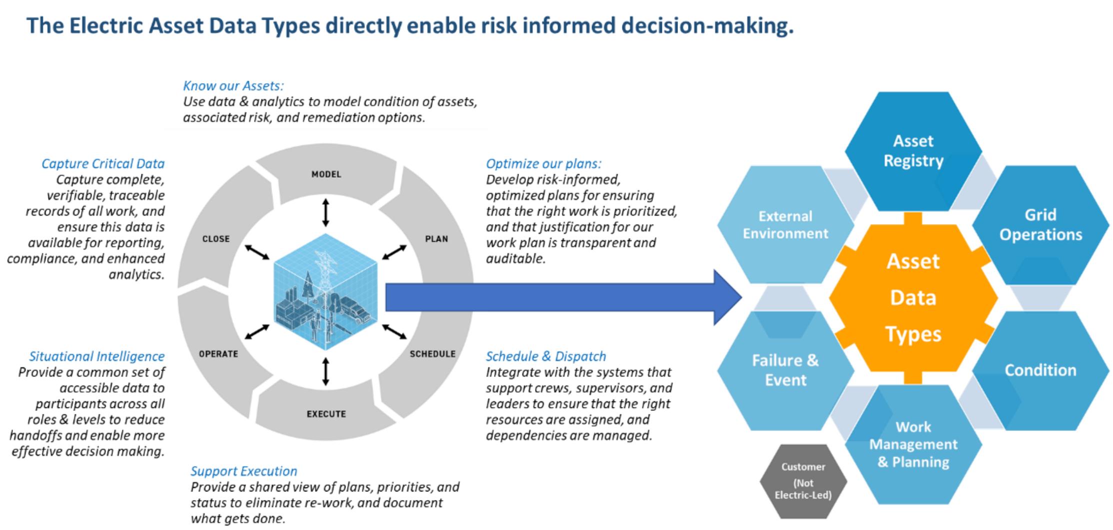
PG&E uses several asset inventory and condition databases. Geographic Information System (GIS) is the system of record for electric asset inventory (Asset Registry), spatial location, electrical connectivity, and attribute data. Asset Registry data is generally stored in GIS databases that are specific to each functional area—Electric Distribution, Electric Transmission, and Substation GISs (also known as Electric Distribution Geographic Information System (EDGIS), Electric Transmission Geographic Information System (ETGIS), and Electric Substation Geographic Information System (ESGIS).

Additional asset detail information may be stored in supplemental databases. Inspection and condition data is generally stored in SAP. SAP is the system of record for asset inspection records, asset condition, and work management records. The inspection, condition, and work management data in SAP is linked to GIS asset record data via a unique identifier (natural key).

Processes are defined to keep asset records aligned among the systems. When asset hardening, maintenance, and remedial work is completed, core asset records in GIS are updated through the As-Built process. When Asset Registry errors or missing data (null fields) are identified through inspections and/or other processes, required changes to the asset records in GIS are evaluated and updated as appropriate via a standardized Map Corrections process. Critical asset records and attributes required for inspection and maintenance purposes are then synchronized from GIS to SAP through system interfaces to ensure that the asset information is consistent.

Installing, managing, and maintaining PG&E's extensive electric asset portfolio requires many data sources and data types that need to be referenced and available to support advanced analytics, modeling, and decision making. To manage and maintain this portfolio we have developed the Electric Asset Data Framework, illustrated in Figure PG&E-8.1.5-1 below.

FIGURE PG&E-8.1.5-1:
ELECTRIC ASSET DATA FRAMEWORK



The core Asset Inventory (Asset Registry) and Condition databases that are the focus of this section are represented in this framework. The value of this data can be enhanced by integrating it with operating data, event/failure data, and externally sourced data within our Palantir Foundry enterprise data and analytics platform to provide centralized access to a more comprehensive, integrated set of asset-related data. For example, the ability to integrate Operating History and Overload History data (as represented in 2023 Utility Maturity Survey questions 3.1.2.Q2 and 3.1.2.Q3) and correlate it with externally sourced environment data (HFTD, ambient weather, corrosion zones), asset registry data, and failure event data can enable advanced analytics and predictive models.

We have continued building out our Palantir Foundry enterprise data platform to integrate and standardize these separate, purpose-built data sources to improve data access and enable more sophisticated analysis. While many of the core systems (GIS, SAP) have been integrated into Foundry, work remains to be done, both in organizing these datasets and adding additional data sources. To the extent possible, we apply a risk-based prioritization to plan this work, which aligns with the objectives of maturing our asset inventory and condition database as identified in Section 3.1 of the 2023 Wildfire Mitigation Maturity Survey. In answering the 2023 Maturity Survey questions, our interpretation of the term "asset inventory and condition database" is defined as the Foundry platform that enables the integration of the underlying data sources into a centralized system of access.

As of December 31, 2022, we had integrated 55 core systems into the Foundry platform. Further, we have developed 616 distinct data objects (Ontology Objects) representing some of our most critical dataset elements related to wildfire mitigation. From 2023 through 2026, we will continue integrating additional data sources and improving the quality and access of existing sources, consistent with our responses to 2023 Maturity Survey questions in Section 3.1, including the addition of operating history, overload history, and asset condition data to Foundry.

Describe the Utilities Internal Documentation of its Database(s)

As it relates to our core asset inventory and condition systems EDGIS, ETGIS, and SAP platforms, we document the technology components that comprise the databases within our Information Technology Asset Management systems. This includes but is not limited to: the Application Technology Lifecycle and Systems (ATLAS) leveraging software AG Alfabet; our Configuration Management Database (CMDB) leveraging BMC Remedy Atrium technology; and our Asset Management Platform and Services (AMPS) providing a federated portal of our applications and databases.

Additionally, we document how systems relate to GIS databases in project deliverables such as solution blueprints, high-level architecture diagrams, system architecture diagrams, and other documentation.

As it relates to our SAP platform, PG&E Electric Distribution and Electric Transmission maintenance and inspection records are maintained in the SAP Enterprise Asset Management module. Additionally, we document SAP technology through project deliverables including solution blueprints, reference architecture diagrams, functional specifications, and other project documentation in the Atlassian Confluence WIKI platform. SAP QA documentation is housed in HP ALM (Application Life Cycle Management), and SAP solution defects and enhancements are documented in BMC Remedy. SAP model and schema governance is a managed standard change control process that promotes changes from the development to production system. An SAP mapping table is maintained for the GIS to SAP standard data model. A standard testing and business sign-off process is used for any SAP change.

There are defined processes to govern and execute updates to these core technologies and databases. These processes are used to make requested changes and enhancements to the system. This includes intake, prioritization, discovery, design, build, testing, and releasing changes into the production database. This covers system changes such as schema updates, software upgrades, configuration, and custom solutions.

To ensure we have a shared understanding of critical asset data, in 2022 PG&E initiated an effort to document and maintain centralized metadata in its enterprise data catalog, Collibra. The data catalog contains technical and business metadata for critical asset data sources and datasets. PG&E has captured within Collibra an inventory of Critical Data Assets and metadata relating to the Asset Inventory for targeted distribution and transmission physical assets on a risk-prioritized basis. Examples of metadata stored in Collibra include the system of record, the data lineage, the source table, data type, data profiling information, a business-friendly definition of the data element, and data quality rules applied to the Critical Data Element (CDE).

Further, the Foundry data platform includes documentation of the developed data objects (Ontology Objects), which provide consistent access to the curated datasets, while also supporting the implementation of data quality rules and dashboards. As it relates to our Foundry platform, analytic use cases are documented in product documentation stored on SharePoint. This includes business requirements, solution designs, and testing and delivery records. Enhancements and changes to existing use cases are added to this documentation as they are developed and delivered.

New requests for Foundry data platform products and major changes to existing products are proposed through an intake process managed in SMC/Remedy and are evaluated, approved, and prioritized by the Analytic Product Strategy team.

Datasets that support the products are documented in the Foundry platform tools including Ontology Ownership and Maturity Tracker, Data Source Tracker, Ontology Management Application, Data Lineage tool, and Data Catalog tool. Data fidelity and quality is measured and monitored using Foundry processes and is tracked and reported in Foundry dashboards and Collibra.

Reported issues, failures, and requested changes are recorded in the Foundry Issues tool where they are managed and resolved by Platform Operations and records are retained. Resolution of issues and design changes to existing products follows a managed Change Management process that coordinates with any external affected system(s). Change documentation is maintained with the original product documentation.

Data security, privacy, and access control is managed by MyElectronicAccess (MEA) and is governed by the Platform Operations team. Documentation of user access and privileges is maintained in MEA. Documentation of the security model, user roles, and associated privileges is maintained by the Platform Operations team.

General documentation about the Foundry platform technology including development and management standards is maintained in the Foundry Documentation Library, in SharePoint, and in the Confluence Wiki platform.

Integration With Systems in Other Lines of Business

As it relates to EDGIS and ETGIS, there are key integrations with systems in other lines of business to support critical business processes. These include integration with Vegetation Management (VM) systems to support alignment of VM work with critical electric assets, with Power Generation systems to support identification of Power Generation assets that are captured in EDGIS/ETGIS, and with operational systems such as the Distribution Management System (DMS) to support asset identification. The integrations with other systems are documented as part of the Information Architecture in ATLAS. For each integration, this system can capture source application, target application, connection method, connection type, connection frequency, connection data format, description, and associated business data type. The system provides a unique identifier for each integration/information flow.

Critical information related to asset details and condition, including inspections, maintenance, repairs, outage events and other activities, is stored in many databases across the enterprise. Our strategy is to integrate this data into the Foundry data platform and to rationalize and retire many of these databases following our risk-based prioritization model. Foundry datasets are regularly refreshed from the source system and checked for fidelity against the source system to ensure data is aligned. Integration with Foundry provides a consistent and controlled access layer for analytics and decision making. All Foundry integrations are discoverable through Foundry's data lineage tool.

There are defined processes that monitor the technology synchronization among key databases, including ETGIS/EDGIS and SAP. This monitoring includes daily interface success or failure reports, notifications when automated processes steps are completed, and notifications when manual steps are needed. The solution logs the details about the record synchronization and issues that need to be resolved.

Weekly reports are generated summarizing synchronization results between GIS and SAP at the asset-record and data-field level. These reports show how many records are out of sync and show trending over time. They include information about the records that are out of sync and are used to identify necessary corrective actions. The report lists issues that were not resolved in the prior week and is also used to identify preventive actions.

Integration With the Auditing System(S) (See QA/QC Section Below)

In general, QA/QC processes and results are managed within program-specific databases. If future use cases indicate value from integrating this data, we will evaluate the opportunity.

Regarding the Asset Inventory and Condition database systems, we have implemented several data quality and audit mechanisms. PG&E has implemented an Asset Registry Data Quality program to enable measurement of data quality for our critical data assets by subject matter experts (SME) consistent with Questions 3.1.4.Q1, 3.1.4.Q3, 3.1.4.Q5 in the 2023 Utility Maturity Survey. We describe this program in new initiatives below.

Although not a detailed technical audit, Lloyds Register has audited and approved PG&E's asset data management practices consistent with ISO 55001. This includes practices to define our critical asset data inventory, understand the condition of that inventory, assess the risk associated with the data condition, and apply strategies to mitigate that risk.

Additionally, PG&E provides our Spatial Quarterly Data Report (QDR) in which we share substantial data related to our assets, wildfire mitigation related initiatives, and other information to Energy Safety and the California Public Utilities Commission (CPUC). Energy Safety engages electrical corporations after every submission through a technical workshop to discuss data gaps and findings. These workshops help us prioritize our data quality efforts. PG&E also was subject to a formal audit on our Spatial QDR in late December of 2020 from Energy Safety (at the time, Wildfire Safety Division (WSD)) where they released a QC report on our first quarterly submission (September 9, 2020). This report included detailed findings about data completeness and the quality of the GIS data we submitted. PG&E proactively made progress against, or fully addressed, Energy Safety's findings. Certain findings were no longer required as Energy Safety evolved its Data Standard requirements.[129]

SAP is audited for SOX compliance at least annually by PG&E's internal audit team and by our external auditors related to changes and access level. In addition, we have implemented data creation access controls so that only users with asset create/change authorization can update data and authorization controls for read-only access.

Describe Internal Processes for Updating Enterprise Systems Including Database(s) and Any Planned Updates

Information Technology (IT), with its business partners, regularly evaluates the effectiveness and health of enterprise IT systems. They develop plans to update, upgrade, or replace and retire IT systems to maintain acceptable system health and ensure business needs are met. Major changes are reflected in PG&E's regulatory filings such as our General Rate Case. Smaller changes are planned in our Value Stream work prioritization sessions. Listed below are some of the major enterprise IT system changes planned for the near term.

- Asset Inventory Database: GIS upgrade to Esri Utility Network Model, including consolidation of ETGIS, EDGIS, and Substation GIS systems into a single foundation system. Planning and design will begin in 2023 and is expected to be fully implemented by 2026. This will simplify systems and processes by establishing a single GIS schema and Asset Registry for all electric assets. Further, the Utility Network Model will provide enhanced capabilities to support electrical connectivity and asset state information, including as-switched topographies and historical views.

- Asset Condition Database: SAP upgrade to S4/HANA, including redesign of several related processes. Planning and design will begin in 2023. This will provide improved capabilities for asset and work management processes and support improved synchronization with other systems.

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[129] WSD QC Report on GIS Data Submitted by PG&E on September 9, 2020 (Dec. 2020). See Appendix E.

- Foundry Data Platform: Continuing development of a fully integrated, centrally managed, and discoverable critical asset data source, including further development of Foundry.

- Deployment of Snowflake (Cloud-Based Data Storage): This will replace legacy on-site data warehousing and provide enhanced data storage and access capabilities.

- Selection and Deployment of an Enterprise Data Quality Management Tool: This will augment data quality rules captured in Collibra and potentially replace data quality rules engine functionality currently implemented in Foundry, thereby providing more direct data quality management in the source systems.

- Development of an Enterprise Logical Data Modeling Practice And System: This will provide an improved understanding of the definitions and relationships of data elements across all systems.

- Development of a Central Repository for All Remote Sensing Data (Aerial Imagery, Light Detection and Ranging (LiDAR) Point Cloud Data, and Satellite Imagery): This and a link to asset inventory and condition data to provide access and enhanced analytics and insight capabilities related to this data.

Any changes to the initiative since the last WMP submission and a brief explanation as the why those changes were made. Include any planned improvements or updates to the initiative and timeline for implementation.

The 2023 WMP Guidance significantly restructured the approach to Data Governance, moving from a centralized discussion of the topic to separate data-related sections for key initiatives. As such, this section does not fully integrate all elements of the initiative described in the 2022 WMP Data Governance Section (7.3.7.1). Instead, this section focuses specifically on Data Governance as it relates to Asset Inventory and Condition databases. While this was a key theme of the 2022 WMP Data Governance discussion, we also discussed Foundry data and analytic products that directly support specific wildfire mitigation efforts and are not part of asset inventory and condition data management/governance initiatives aimed at the Asset Inventory and Condition database. As such, we do not discuss the Foundry data and analytic products in this section.

In January of 2022, PG&E hired our first Chief Data and Analytics Officer (CDAO), signaling a significant commitment from executive leadership to ensure data is managed as a critical and strategic asset across the enterprise. Reporting to the CDAO, the new Enterprise Data Management organization is focused on establishing an enterprise approach to four critical data management capabilities: data governance; data quality management; metadata management; and data protection.

The Electric Asset Knowledge Management (AKM) organization has specific accountability to manage critical electric data as an asset in accordance with ISO 55001 requirements. In 2022, this group executed a number of critical projects to address key asset data risks and gaps that directly support wildfire mitigation. Further, several foundational programs were initiated to mature data management practices with a focus on Asset Inventory and Condition databases. A comprehensive list of completed and ongoing programs and projects is provided in ACI PG&E-22-33. Current critical initiatives include:

- ISO 55001 Certification for Asset Management: PG&E manages our asset-related data consistent with ISO 55001 asset management standards. PG&E develops and maintains an Asset Management Plan (AMP) to define our approach to managing our core asset-related data, as well as our physical assets. These plans are regularly reviewed by PG&E senior leadership and PG&E's conformance to ISO 55001 is audited by external parties (LRQA, formerly Lloyds Register).

- Asset Registry Standard (TD-9212S): Defines the System of Entry and System of Record for all critical electric assets and establishes system and process governance. This standard was released in September 2022. It is being implemented across all Electric Asset families with full conformance expected by 2026.

- Asset Registry Data Quality Program: This program was developed in partnership with the new Enterprise Data Management organization to systematically measure the data quality of critical datasets, identify critical gaps for remediation, and track ongoing status and improvements. As of December, 2022, this program has identified 573 CDEs and documented their metadata in support of 12 Transmission and Distribution asset types that comprise 86 percent of wildfire risk. A total of 1,636 data quality rules have been implemented, including rules to measure completeness and conformity of CDEs, such as Installation Date, Material Type, and Manufacturer. The program will continue to expand to support all electric critical assets and associated condition data by 2026. This program directly supports objectives related to Maturity Survey questions 3.1.2.Q1, 3.1.2.Q7, 3.1.4.Q1, 3.1.4.Q3.

- As-Built Process Ownership and Introduction of Digital As-Built Program: In 2022, the Electric AKM team established additional governance of the As-Built processes and initiated a program to digitally capture critical asset data during the process to reduce manual data entry and related errors, and to reduce the cycle time for asset record creation.

8.1.6 Quality Assurance and Quality Control

In this section, the electrical corporation must provide an overview of its QA/QC activities for asset management and inspections. This overview must include:

- *Reference to procedures documenting QA/QC activities;*
- *How the sample sizes are determined and how the electrical corporation ensures the samples are representative;*
- *Qualifications of the auditors;*
- *Documentation of findings and how lessons learned based on those findings are incorporated into trainings and/or procedures;*
- *Any changes to the initiative since the last WMP submission and a brief explanation as to why those changes were made. Include any planned improvements or updates to the initiative and the timeline for implementation; and*
- *Tabular information that includes:*
  - *Sample sizes;*
  - *Type of QA/QC performed (e.g., desktop or field); and*
  - *Resulting pass rates, starting in 2022.*

Yearly target pass rate for the 2023-2025 WMP cycle Table 8-7 provides an example of the appropriate level of detail.

8.1.6.1 Quality Assurance

- **Utility Initiative Tracking ID:** GM-01

Overview

We plan to implement a QA program for systems inspections. While we have not set specific targets for this Initiative and will not provide ongoing reporting each quarter on it, we are still doing the work as part of our overall plan. The QA program will be intended to ensure that the QC function is performing as intended through ongoing field-based audits of completed QC locations. QA may also be leveraged to perform process audits in the future.

A Quality Verification (QV) function will be performed in 2023 that provides analysis and program value. The function historically referred to as QV is included within the QA program referred to above.

We plan to update existing QV procedures for systems inspections.

QV uses a statistically valid random sample of QC complete locations. Sample sizes are based on completed QC work. QV audits will be ongoing so long as QC is operational.

All auditors are required to meet the following minimum requirements:

- High School diploma or General Educational Development Test (GED);
- Utility industry experience;
- 7 years job related experience;
- Qualified Electrical Worker (QEW) Certification; and
- Electric utility Apprentice Program training completion.

The minimum requirements are subject to change based on needs of the program and required expertise.

All QV discrepancies are documented in the electronic QC Review Assessment forms. Dashboards are used to show trends and any discrepancies using pre-determined metrics. Stakeholders use these QC Dashboard results to provide training and coaching and to develop corrective actions for training material/procedure updates.

Focusing on completed QC locations is a new strategy we are implementing for QV to ensure effective layers of defense in System Inspection quality.

TABLE 8-7-1:
GRID DESIGN AND MAINTENANCE SYSTEM INSPECTION QA PROGRAM

Inspection Type	Sample Size 2023 projected counts	Type of Audit	Audit Results 2022 as of 12/1/22 (Critical Pass Rate)	Yearly Target Pass Rate for 2023-2025 (Critical Pass Rate)
Transmission	300	Field	N/A. This work was not performed in 2022.	N/A. Target pass rates will be evaluated for 2024 based on the results of our work in 2023.
Distribution	1,200	Field	N/A. This work was not performed in 2022.	N/A. Target pass rates will be evaluated for 2024 based on the results of our work in 2023

8.1.6.2 Quality Control

Overview

Reference to procedures documenting QA/QC activities

System Inspection QC Standard is currently being developed. We anticipate completing this standard by Q1 2023.

Please refer to Section 8.1.6.1 for a description of our QA program.

How the sample sizes are determined and how the electrical corporation ensures the samples are representative

QC personnel create an annual sampling plan based on the year's workplan. Sample sizes are determined by the sampling plan that is reviewed annually and incorporates a representative and statistically valid sample.

Representative Sample: Drawn from a population of interest. Demographics and characteristics of the sample match those of the population of interest in as many areas as possible; and

Sample Selection: Selection may be random or targeted.

Statistically valid sampling plans will be established and will use key system risk information to select the appropriate confidence level.

Qualifications of the auditors

All auditors are currently required to meet the following minimum requirements:

- High School diploma or GED;
- Utility industry experience;
- 7 years job related experience;
- QEW Certification; and
- Electric utility Apprentice Program training completion.

The list of minimum requirements is subject to change based on needs of the program and required expertise.

Documentation of findings and how lessons learned based on those findings are incorporated into trainings and/or procedures.

QC discrepancies are documented in the electronic QC Review Assessment forms. Dashboards are used to provide trends and discrepancy data using pre-determined metrics. Internal and external stakeholder use these QC Dashboard results to provide training and coaching and to develop corrective actions for training material/procedure updates.

The QC team develops content for the New Inspector Training that includes an overview of the top trends and findings from the previous program year. In addition, the QC team is a regular participant and cross functional collaborator for Inspect App updates, Standards and Job Aid update working sessions, and provides necessary feedback on gaps and continuous improvements opportunities.

PG&E addresses findings by:

- Revising policies, standards, procedures, checklists, and/or tools;
- Additional training;
- Weekly stakeholder meeting to communicate the previous weeks findings;
- Reviewing the System Inspection QC Dashboard with functional area representatives; and
- Discussing findings and trends in daily operating review meetings.

Functional area leadership is responsible for using QC data to drive system inspection improvements. On a quarterly basis (close-out) QC will submit a Corrective Action Plan containing findings summary, trending metrics and overall program results. Functional areas leaders are responsible for developing strategies and corrective actions to address system inspection findings.

Any changes to the initiative since the last WMP submission and a brief explanation as the why those changes were made. Include any planned improvements or updates to the initiative and timeline for implementation.

We evaluate the QC Program annually focusing on efficiency, effectiveness, stakeholder engagement, application of lessons learned, and close out procedures.

New programs are tested and may be added to the QC Program. For example, QC for PT&T has been added to PG&E's Quality Management Program to improve the quality of PT&T based on internal and external stakeholder feedback.

TABLE 8-7-2:
GRID DESIGN AND MAINTENANCE SYSTEM INSPECTION QC PROGRAM

Inspection Type	Sample Size 2023 projected counts	Type of Audit	Audit Results 2022 as of 12/1/22 (Critical Pass Rate)	Yearly Target Pass Rate for 2023-2025 (Critical Pass Rate)
Transmission	30,000 Statistically Valid Sample (minimum estimated at 19,864)	Desktop	92.1%	To be determined. Pass rates will be determined each year based on improving performance year over year.
Transmission	1,200 Statistically Valid Sample (minimum estimated at 4,076)	Field	80.9%	To be determined. Pass rates will be determined each year based on improving performance year over year.
Distribution	200,000 Statistically Valid Sample (minimum estimated at 19,864)	Desktop	85.5%	To be determined. Pass rates will be determined each year based on improving performance year over year.
Distribution	40,000 Statistically Valid Sample (minimum estimated at 6,876)	Field	79.3%	To be determined. Pass rates will be determined each year based on improving performance year over year.

8.1.7 Open Work Orders

8.1.7.1 Open Work Orders – Transmission Tags

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. 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 how work orders are prioritized based on risk;*
- *A description of the plan for eliminating any backlog of work orders (i.e., open work*
- *orders that have passed remediation deadlines), if applicable; and*
- *A discussion of trends with respect to open work orders.*

In addition, each electrical corporation must:

- *Graph open work orders over time as reported in the QDRs (Table 2, Metrics 8.a and 8.b); and*
- *Provide an aging report for work orders past due (Table 8-8 provides an example).*

In addition, each electrical corporation must graph open work orders over time as reported in the QDRs.

Utility Initiative Tracking ID: GM-02

Prioritization of open work orders (notifications) uses the priority levels A, B, E, and F that are defined in the ETPM Manual, TD-1001M. The B priority for notifications is being phased out, and while no new notifications will be created with this priority, existing B-priority notifications will continue to be closed in 2023. Priority E notifications now can be created with 3-month deadlines and these short duration E notifications will be addressed in the same manner as the former priority B. A significant increase in the number of notifications created since 2019 has led to a backlog of E and F notifications requiring additional prioritization. Per PG&E’s Transmission LC Notification Strategy Procedure (TD-8123P-101), ignition-related notifications in HFTD and HFRA areas have a higher priority than non-HFTD and non-HFRA, and non-ignition-related notifications.

The 2022 work plan included completing all HFTD and HFRA ignition-related notifications found in 2021 or earlier, barring external factors. Since this plan contained and mitigated most open ignition-related notifications, there was no further prioritization by wildfire risk at the notification level.

To enable efficient execution, Level E and F notifications were not always repaired by their required deadline, and instead were managed to a target for the end of 2022.

Notifications found before 2023 will be managed similarly, with ignition-related notifications in HFTD or HFRA locations planned to be repaired in 2023 (16,831 notifications), or their required end date if it is after 2023. HFTD or HFRA non-ignition-related notifications opened before 2023 will be repaired opportunistically over the next five years, bundling the work with ignition-related notifications on the same structure or circuit when practical. These actions will enable PG&E to bundle and execute work more efficiently to help reduce the backlog of HFTD and HFRA notifications by the end of 2023.

Starting in 2023, new HFTD and HFRA notifications will be targeted for repair by their required deadlines. These actions will help us to work towards eliminating open HFTD and HFRA ignition notifications due in or before 2023 by the end of 2023. There will continue to be a backlog of notifications in non-HFTD areas that will be prioritized based on public safety risk.

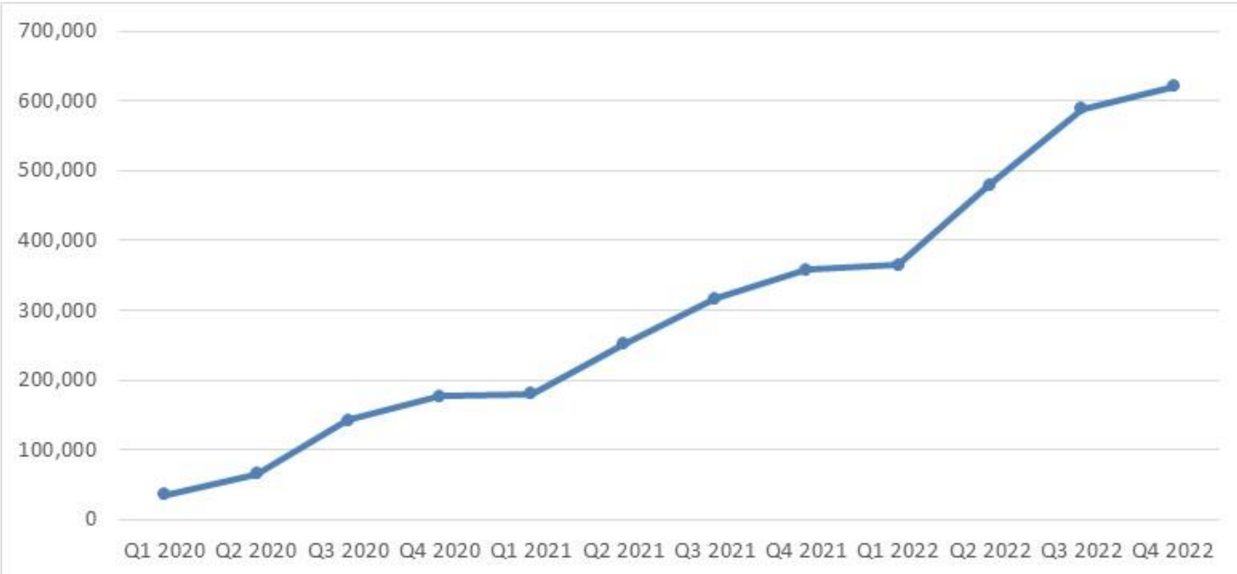
Table 8-8-1 below shows the number of past due Transmission asset work orders categorized by age.

TABLE 8-8-1:
NUMBER OF PAST DUE ASSET WORK ORDERS CATEGORIZED BY AGE
(AS OF JANUARY 3, 2023)

HTFD Area	0-30 Days	31-90 Days	91-180 Days	181+ Days
HFTD-Tier 2	19	104	698	1,665
HFTD-Tier 3	966	1,721	685	688
Zone 1	–	–	1	1
HFRA	3	29	90	94
Non-HFTD	561	3,747	6,229	12,293

Figure PG&E-8.1.7-1 below shows the open work orders in HFTD areas from Q1 2020 through Q3 2022 for Electric Distribution, Electric Transmission, and Electric Substation.

FIGURE PG&E-8.1.7-1:
OPEN WORK ORDERS OVER TIME AS REPORTED IN THE QDRs



8.1.7.2 Open Work Orders – Distribution Tags

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. 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 how work orders are prioritized based on risk;*
- *A description of the plan for eliminating any backlog of work orders (i.e., open work orders that have passed remediation deadlines), if applicable; and*
- *A discussion of trends with respect to open work orders.*

In addition, each electrical corporation must:

- *Graph open work orders over time as reported in the QDRs (Table 2, Metrics 8.a and 8.b); and*
- *Provide an aging report for work orders past due (Table 8-8 provides an example).*

Utility Initiative Tracking ID: GM-03; GM-04; GM-05

Introduction

In 2019, PG&E began 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.[130]

Along with the WSIP inspections, other programs added notifications to the backlog such as PT&T, Post-Event Patrols, Patrol Inspections, and Infrared Inspections.

At the end of 2022, we had approximately 260,000 notifications in our distribution HFRA/HFTD backlog. 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.

We have developed a plan to reduce the wildfire risk associated with the backlog of ignition-risk tags in HFTD/HFRA by 77 percent at the end of the 2023-2025 WMP cycle.

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130 We use notifications, tags, and work orders interchangeably in this section.

- Starting with 151.1 risk units[131] as of January 1, 2023, we will reduce wildfire risk associated with backlog ignition-risk tags in HFTD/HFRA by 72.5 risk units (48 percent) by the end of 2023, barring external factors.
- We will reduce 68 percent of the wildfire risk associated with backlog ignition risk tags in HFTD/HFRA from 151.1 (risk units as of January 1, 2023) by 102.7 (68 percent) risk units by the end of 2024, barring external factors.
- We will reduce 77 percent of the wildfire risk associated with backlog ignition risk tags in HFTD/HFRA from 151.1 (risk units as of January 1, 2023) by 116.3 (77 percent) risk units by the end of 2025, barring external factors.

Along with reducing wildfire risk related to backlog ignition risk-tags in HFTD/HFRA, new (EC notifications identified after January 1st, 2023) HFTD/HFRA ignition risk tags will be completed in compliance with GO 95 rule 18 timelines, barring external factors.

In the narrative below we: describe how we prioritize work orders based on risk; explain our risk-informed plan for eliminating the backlog of ignition-risk tags in the HFTD/HFRA; and analyze our open work orders.

In this narrative we also address the two ACIs related to distribution tags:

- ACI PG&E-22-17; and
- ACI PG&E-22-22.

Reference to Procedures Documenting the Work Order Process

The procedure documenting PG&E's work order process can be found in the Electric Distribution Maintenance Requirements (TD-2305S) and the Electric Distribution Preventive Maintenance (EDPM) Manual (TD-8123M).

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 are assigned a priority based on the potential safety impact.

Open work order (tags or notifications) prioritization uses priority levels the A, B, E, F, and H that are defined in the EDPM. Table PG&E-8.1.7-1 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 There is a known issue with the starting number of risk units. We found that the lat/long data point is incorrect on certain notifications. As a result, certain records show an incorrect location (HFTD/HFRA vs. non-HFTD/HFRA). We also found that certain FDAs are counted incorrectly and therefore display no wildfire risk where there is wildfire risk.

TABLE PG&E-8.1.7-1:
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	B (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).	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.	Corrective action within 3 months for potential violations that create risk of at least moderate potential impact to safety or reliability
3		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).	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 compromised worker safety; and 36 months for all other Level 2 potential violations.	Corrective action within: 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. Field Safety Reassessment (FSR) performed annually on time dependent tags to confirm Priority E Notification has not escalated to Priority A or B. If notification has escalated to Priority A or B, address according to timelines above.

TABLE PG&E 8.1.7-1:
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		H (Electric)	These are PG&E Priority "E" Notifications that are planned to be addressed by a planned System Hardening Project.	Same as above.	Field Safety Reassessment performed annually on time dependent tags to confirm Priority E Notification has not escalated to Priority A or B. If notification has escalated to Priority A or B, address according to timelines above.
5	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 for distribution assets to be addressed within five years from date condition is identified. Corrective actions for transmission assets to be addressed within two 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 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; and

- Priority B tags are addressed within 3 months for potential violations that create risk of at least moderate potential impact to safety or reliability.

We divide remaining notifications into two groups: (1) ignition risk notifications in the HFTD/HFRA; and (2) non-ignition risk notifications in the HFTD/HFRA. Ignition risk notifications in HFTD/HFRA areas are the highest priority in this group of notifications.

- In 2023, new HFTD/HFRA ignition risk tags (EC notifications identified after January 1st, 2023) will be completed in compliance with GO 95 rule 18 timelines, barring external factors; and

- Tags identified prior to 2023 will be prioritized by considering risk. We will bundle work by isolation zones in 2023 to reduce customer impact and improve operational efficiency and safer coworker conditions. We will reduce the wildfire risk associated with backlog ignition-risk tags in HFTD/HFRA by 48 percent.

PG&E's Plan for Eliminating the Backlog of Open Work Orders

PG&E has developed a two-tiered approach to reduce our backlog of open work orders:

1) Reduce the backlog of approximately 210,000 ignition-risk notifications in the HFTD/HFRA by the end of 2029; and

2) Address new notifications.

The plan addresses our full backlog of ignition-risk notifications in the HFTD/HFRA. This plan responds to information required by ACI PG&E-22-22.

Plan to Reduce the Backlog

We will reduce the backlog using a risk-informed approach. Our plan consists of working the highest ignition-risk notifications in the HFTD/HFRA in 2023 and then transitioning to a risk spend efficiency (RSE) approach starting in 2024.

- In 2023 we will identify and work the highest ignition-risk notifications in the HFTD/HFRA. We will identify any other open work orders that are in the same isolation zone as the highest risk notifications. We will bundle the other open work orders in the same isolation zone with the highest risk notifications and work them together.

- Starting in 2024, we plan to calculate the RSE for each isolation zone. We will address the remaining ignition-risk HFTD/HFRA open notifications by isolation zone (each isolation zone will include multiple tags), starting, generally, with the isolation zones with high RSEs.

  - Our plan is to eliminate the ignition-risk notification backlog by the end of 2029 and to eliminate the non-ignition risk backlog by the end of 2032. Level 2 and Level 3 notifications are described in Table PG&E-8.1.7-1 above;

  - Non-Pole Repairs and Replacements – Ignition Risk Tags: Since non-pole tags generally create greater ignition risk than pole tags, we are implementing a 3-year plan to address all ignition risk related tags in the HFTD/HFRA. This plan will reduce risk associated with non-pole tags by 63 percent by the end of 2023 and reduce all risk associated with this backlog by the end of 2025; and

  - Since pole tags present a lower ignition risk and often require additional planning and permitting, resulting in a longer execution timeline, we are implementing a 7-year plan to address all ignition-risk related pole tags. This plan will reduce risk associated with pole tags by 23 percent by the end of 2023 and reduce all risk associated with this backlog by the end of 2029.

- We will not work individual non-ignition risk notifications in the HFTD/HFRA from 2023 through 2029 unless they are opportunistically addressed or included in isolation zone work bundles. We will begin closing targeted non-ignition risk notifications after 2029.

Plan to Address New Notifications

- New (EC notifications identified after January 1, 2023) HFTD/HFRA ignition risk tags will be completed in compliance with GO 95 rule 18 timelines, barring external factors; and

- New non-ignition-risk, HFTD/HFRA notifications will not be worked individually but they may be included in work bundles as described above.

Table PG&E-8.1.7-2 below provides the quantitative targets for addressing repairs for infractions found during inspections, broken down by severity level of the finding, and accounting for the entire ignition-risk HFTD/HFRA backlog.

Table PG&E-8.1.7-2 below provides the information required by ACI PG&E-22-17.

TABLE PG&E-8.1.7-2:
ADDRESSING INFRACTIONS FOUND DURING INSPECTIONS, BROKEN DOWN BY SEVERITY LEVEL OF THE FINDING

	Ignition-Risk HFTD/HFRA Notifications				
	Non-Pole (A)	Pole (B)	Total (C) = (A)+ (B)	Non-Ignition Risk HFTD/HFRA (D)	Total Notifications (E) = (C) + (D)
Backlog as of Jan. 1, 2023	114,000	96,000	210,000	50,000	260,000
Year 1: 2023	(24,000)	(5,000)	(29,000)		(29,000)
Year 2: 2024	(41,000)	(5,000)	(46,000)		(46,000)
Year 3: 2025	(49,000)	(6,000)	(55,000)		(55,000)
Total Notifications Closed	(114,000)	(16,000)	(130,000)	0	(130,000)
Total Notifications Remaining at the end of the 2023-2025 WMP cycle	0	80,000	80,000	50,000	130,000
Year 4: 2026(a)		(18,000)	(18,000)		(18,000)
Year 5: 2027		(18,000)	(18,000)		(18,000)
Year 6: 2028		(22,000)	(22,000)		(22,000)
Year 7: 2029		(22,000)	(22,000)	(12,000)	(34,000)
Year 8: 2030				(12,000)	(12,000)
Year 9: 2031				(13,000)	(13,000)
Year 10: 2032				(13,000)	(13,000)
Total Remaining	0	0	0	0	0

ACI PG&E-22-22 states that by the end of 2023 PG&E must develop a plan detailing how it will clear the GO repair backlog no later than the end of the 2023-2025 WMP cycle and demonstrate its capability to maintain its repair cycle within GO requirements. PG&E must include this plan in its WMP Update submitted in 2024.

Table PG&E-8.1.7-2 above shows that we will clear approximately 130,000 ignition-risk HFTD/HFRA tags by the end of the 2023-2025 WMP cycle.

During the 2023-2025 WMP cycle we will address the highest risk tags in the HFTD/HFRA and plan to reduce the wildfire risk associated with them by 77 percent. We will also work new ignition-risk, HFTD/HFRA notifications as required by GO 95 Rule18 so that we do not increase our ignition risk backlog.

Based on our current plan, we will not clear the GO repair backlog by the end of the WMP cycle. Our workplan represents a balance between reducing the highest risk tags in our backlog and addressing new tags. We will provide an update to Energy Safety about our plans to reduce our distribution tag backlog in our WMP update submitted in 2024.

Resource Plan for Closing Outstanding and Overdue work orders in the HFTD/HFRA

This resource plan provides information required by ACI PG&E-22-22.

Our 2023 resource plan is based on working approximately 1.8 million hours. We anticipate increasing our hours by approximately 5 percent each year over the WMP cycle. We will update our resource plan in our 2024 WMP Update.

Work Order Aging Report and Progress in 2022 and Analyzing Open Work Order Trends

PG&E is unable to provide the number of past due asset work orders, categorized by age, in the HFTD from Q1 2020 through Q3 2022.

Figure PG&E 8.1.7-1 above shows open Transmission, Distribution, and Substation asset work orders over time as reported in the QDRs from 2020 through 2022.

We have seen a steady increase in open notifications from Q1 2020 through Q3 2022.

In 2021 and 2022 we closed more than 350,000 tags across the distribution system. At the same time there were increases to the backlog due to higher than anticipated new tags opened. The backlog grew by more than 615,000 tags in 2021 and 2022. Backlog growth is higher among non-HFTD assets due to the prioritization of ignition risk tags.

Considering only the subset of tags in the HFTD/HFRA, in 2021 and 2022 we closed approximately 195,000 tags and opened more than 234,000 tags. The increase in the backlog in the HFTD/HFRA was proportionally smaller (approximately 27 percent in the HFTD/HFRA compared to approximately 61 percent across the distribution system) because we prioritize closing the higher risk tags.

In 2022 our work order backlog increased across the distribution system. We saw a 17 percent increase in find rates from 2021 to 2022. Changes in the inspection process in 2021 is a key driver of the tag backlog increase. A renewed focus on training and the quality of inspections likely increased the find rate significantly between 2021 and 2022. Key process changes from 2021 to 2022 included improvements to: inspector training; our skills assessment; and the inspection checklist. We also implemented QC desk and field reviews and a weekly inspection findings review-session with our supervisors.

We expect that we will see more A and B tags during this WMP cycle because we will be conducting more advanced inspections including Aerial Inspections, LiDAR, Pole Loading, and Intrusive Pole Inspections. These inspections are expected to contribute to the number of tags being created. Finding more A and B tags could lead to resource challenges because we would prioritize this high priority, urgent work. Redirecting resources to work on A and B tags could require an offset to the number of backlog notifications closed.

In addition, PGE's Asset Failure Analysis team conducts causal and extent of condition analyses following many equipment failure incidents, particularly when an ignition occurs. The findings of those reports inform corrective actions to mitigate newly understood risk in the system. These corrective actions may involve recommendations to revise our inspection checklist and/or inspection job aid to improve the guidance and/or tools so our inspectors can be more effective in their work. While these revisions of inspection protocols may result in increased tags being written, we ultimately have a more risk-informed workplan and therefore we can more effectively target ignition risk going forward.

Even though our tags backlog increased in 2021 and 2022, we have identified more potential sources of ignition risk and we have learned more about the risk areas on our system. As we proceed in closing these findings, we are continually removing more ignition risk from the highest wildfire risk areas in our system.

Table PG&E-8.1.7-5 and Table PG&E-8.1.7-6 below show the number of tags remaining in 2022 and the number of tags opened and closed in 2022 by quarter.

Tables PG&E-8.1.7-5 and PG&E-8.1.7-6 provide the information required by ACI PG&E-22-22.

TABLE PG&E-8.1.7-5:
DISTRIBUTION SYSTEM WORK ORDERS OPENED/CLOSED IN 2022 BY QUARTER

	Opened	Closed	Addition to Backlog
Open Tags Jan 1, 2022			
1st Quarter	29,492	(43,584)	(14,092)
2nd Quarter	124,826	(37,925)	86,901
3rd Quarter	126,121	(35,815)	90,306
4th Quarter	47,647	(30,612)	17,035
Total	328,086	(147,936)	180,150

Note: As of January 5, 2023.

TABLE PG&E-8.1.7-6:
HFTD/HFRA DISTRIBUTION WORK ORDERS OPENED/CLOSED IN 2022 BY QUARTER

	Opened	Closed	Addition to Backlog
Open Tags Jan 1, 2022			
1st Quarter	10,046	(23,643)	(13,597)
2nd Quarter	58,761	(19,925)	38,836
3rd Quarter	43,941	(18,787)	25,154
4th Quarter	5,678	(14,202)	(8,524)
Total	118,426	(76,557)	41,869

Note: As of January 5, 2023.

8.1.7.3 Open Work Orders – Substation Tags

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. 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 how work orders are prioritized based on risk;*
- *A description of the plan for eliminating any backlog of work orders (i.e., open work;*
- *orders that have passed remediation deadlines), if applicable; and*
- *A discussion of trends with respect to open work orders.*

In addition, each electrical corporation must:

- *Graph open work orders over time as reported in the QDRs (Table 2, Metrics 8.a and 8.b); and*
- *Provide an aging report for work orders past due (Table 8-8 provides an example).*

PG&E performs corrective repairs and equipment replacements identified through maintenance and inspections of substations located in HFTD. This corrective maintenance program is intended to correct deficiencies so that substation equipment operates as designed and mitigates the risk of failure leading to a wildfire ignition.

Corrective work is prioritized and completed based on equipment condition and the risk of failure. Repairs are identified through inspections, and conditions and severities are evaluated individually using the Facility Damage Action (FDA) matrix to determine the impact and to assign a priority code.

The impact and priority codes are documented using a LC notification with an associated repair priority code (A, B, E, or F). Each code specifies the due dates by which the impacted work 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).

The substation LC tag backlog is currently operating at “steady state”. The current backlog of substation ignition risk related tags (found prior to 2022) in HFTD-were resolved by the end of 2022 except for seven LC tags that will be executed in 2023. Going forward, all substation LC tags will be addressed in accordance with the timelines specified in Utility Standard TD-3322S and Utility Procedure TD-3320P-12, barring external factors.

Similarly, Power Generation performs corrective repairs and equipment replacements as described above using Power Generation H1 notifications. Identified issues result in

H1 notifications that are assigned a repair priority code (1, 2, 3, or 4) with specified due dates. While we have not set specific targets for this Initiative and will not provide ongoing reporting each quarter on it, we are still doing the work as part of our overall plan.

Power Generation corrective tag execution is operating at steady state with respect to H1 tags identified in 2021 or earlier that have exceeded their out-of-compliance due date. The small number of tags remaining open have documented justification of external factors affecting the ability to complete work. These tags are being actively managed for ignition risk in HFTD-and HFRA. In 2023, Power Generation intends to continue to manage and execute H1 tags in accordance with compliance commitments.

Table PG&E-8.1.7-7 below shows the number of past due Substation asset work orders categorized by age.

TABLE PG&E-8.1.7-7
NUMBER OF PAST DUE ASSET WORK ORDERS CATEGORIZED BY AGE
(AS OF JANUARY 1, 2023)

HTFD Area	0-30 Days	31-90 Days	91-180 Days	181+ Days
HFTD-Tier 2	0	2	0	2
HFTD-Tier 3	0	1	0	2
Zone 1	0	0	0	0
HFRA	0	0	0	0

Figure PG&E 8.1.7-1 above shows open Transmission, Distribution, and Substation asset work orders over time as reported in the QDRs from 2020 through 2022.

8.1.8 Grid Operations and Procedures

8.1.8.1 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. The equipment settings discussion must include the following:

- *Protective equipment and device settings;*
- *Automatic recloser settings; and*
- *Settings of other emerging technologies (e.g., Rapid Earth Fault Current Limiters (REFCL)).*

For each of the above, the electrical corporation must provide a narrative on the following:

- *Settings to reduce wildfire risk;*
- *Analysis of reliability/safety impacts for settings the electrical corporation uses;*
- *Criteria for when the electrical corporation enables the settings;*
- *Operational procedures for when the settings are enabled;*
- *The number of circuit miles capable of these settings; and*
- *An estimate of the effectiveness of the settings.*

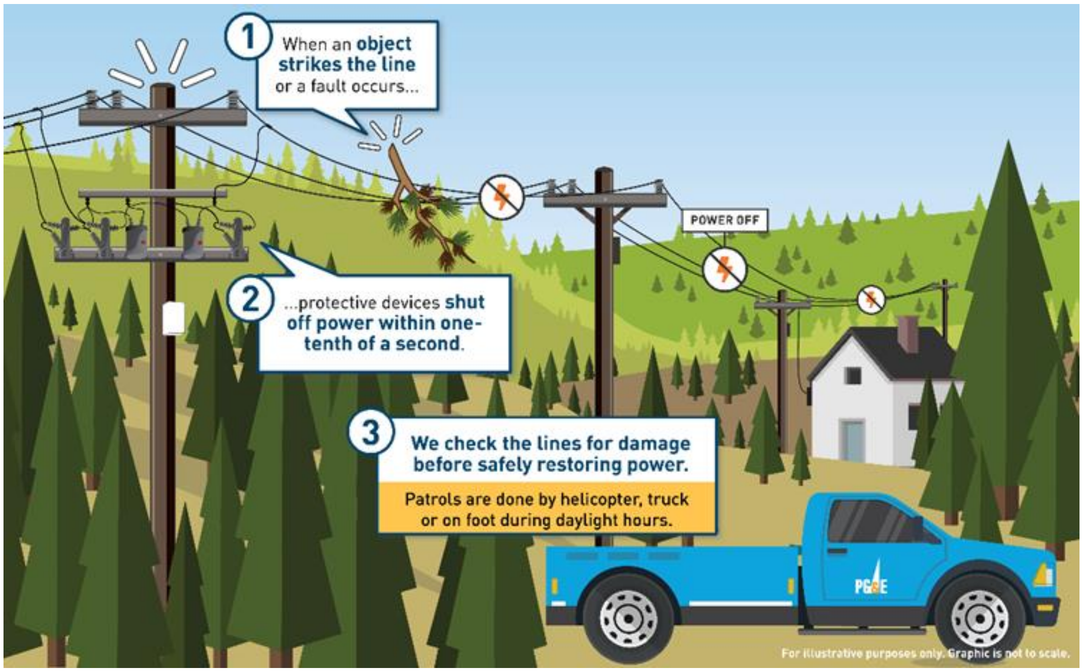
8.1.8.1.1 Protective Equipment and Device Settings

- **Utility Initiative Tracking ID:** GM-07

Settings to Reduce Wildfire Risk

When EPSS are enabled on distribution and transmission line protective devices, power automatically turns off within one-tenth of a second if a threat is detected on the line that could result in an ignition. This process can be seen in Figure PG&E-8.1.8-1, below.

FIGURE PG&E-8.1.8-1:
EPSS SAFETY OVERVIEW



EPSS is a protective technology that allows line protection devices, such as line reclosers, to address faults of varying magnitude and rapidly de-energize the line. These faults may occur due to vegetation striking a line, animal interference, third-party interference (e.g., a vehicle hitting a line) or equipment failure.

Circuits enabled with EPSS are configured to clear high-current 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 backfeed into the fault.

Additionally, when EPSS is enabled on three-wire distribution systems, Sensitive Ground Fault settings are implemented to help detect lower current fault conditions. This protection is generally set to identify 15 amperage faults within 15 seconds and de-energize the conductor to protect the line.

To further address lower current fault conditions, also referred to as high impedance faults, we plan to engineer, program, and install the Downed Conductor Detection

(DCD) algorithm on recloser controllers. We will also evaluate high impedance fault detection algorithms for circuit breakers in 2023 and beyond. See Section 8.1.2.10 for more information on DCD.

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.

If equipment is in a condition that may increase wildfire risk and partial voltage conditions are detected, Control Center Operators can force out an upstream Supervisory Control and Data Acquisition device at the location where multiple partial voltage alarms are received.

This technology 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 could potentially cause an ignition. If an ignition does occur, first responders can extinguish it more quickly.

EPSS does not cause a power outage. These settings help protect customers and communities from potential ignitions that could result in wildfires by de-energizing the line when a fault is detected on the powerline.

Analysis of Reliability/Safety Impacts for Settings the Electrical Corporation Uses

In 2022, we reduced the Customer Average Interruption Duration Index (CAIDI) and Customers Experiencing a Sustained Outage (CESO) for customers served by EPSS-capable lines when compared to data from the 2021 program pilot. Through the end of 2022, the average CAIDI was 176 minutes—a 56 percent reduction from 2021.

The average CESO through the end of 2022 was 877 customers—a 20 percent reduction from 2021. We focused on responding to all outages on EPSS-enabled circuits within 60 minutes. By the end of 2022, we responded to 89 percent of outages on EPSS-enabled lines within 60 minutes, responding on average within 42 minutes.

Furthermore, more than 1 million customers—58 percent of the customers protected by EPSS—experienced zero outages in 2022. However, on certain circuit segments, EPSS can exacerbate existing reliability issues. Fewer than 7 percent of customers in scope for EPSS in 2022 experienced five or more outages while EPSS protection was enabled. In 2023, we will continue working to improve customer reliability while maintaining wildfire ignition mitigation capability.

We have conducted extensive analysis on the reliability impacts when EPSS is enabled. See ACI PG&E-22-32 for more information about the EPSS Program's effort to enhance program reliability.

Criteria for When the Electrical Corporation Enables the Settings

In 2022, we developed criteria to enable EPSS in HFRAs during conditions that have historically accounted for 97 percent of acres burned and all historical consequences.[132] The criteria for EPSS enablement are based on the Fire Potential Index (FPI). FPI ratings and their definitions are shown in Table PG&E-8.1.8-1 below.

TABLE PG&E-8.1.8-1:
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).

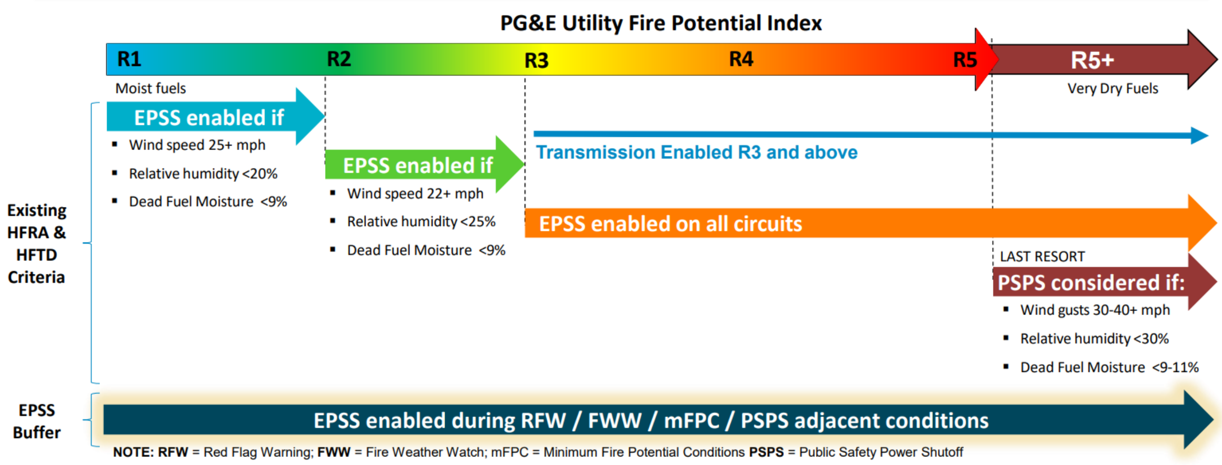
Our current baseline criteria require EPSS enablement when an FPI rating of R3 is forecasted for at least an hour at the distribution circuit level, or when a combination of high sustained wind speed, low relative humidity, and low 10-hour dead fuel moisture are present at R2 or R1.

Transmission enablement criteria differ from distribution enablement 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 and is not transferred in or out of enablement like the distribution system does.

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 8.1.8-2, below, explains the conditions for EPSS enablement. See Section 8.3.6.1 for more information on how FPI is calculated and used in our operations.

132 Consequences include impacted fatalities, structures destroyed, and acres burned based on historical fires > 100 acres from 2012-2020 of any cause.

FIGURE PG&E-8.1.8-2:
FPI EPSS ENABLEMENT CRITERIA



We review multiple meteorological models on a daily basis that indicate—at the individual circuit level—which circuits are forecast to meet EPSS enablement criteria each day. This informs whether circuits need to be enabled for safety 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.

Operational Procedures for When the Settings Are Enabled

We have established the Enhanced Power Line Safety Settings (EPSS) and Patrol Process Procedure (TD-2700P-26) (see Appendix E) that outlines the patrol process when responding to outages on EPSS-enabled circuits. Generally, the process requires that the entire 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 is the process conducted by patrol teams unless an apparent issue is identified (e.g., a vehicle hitting the line or a tree branch falling through the line) and is determined to be the cause of the outage. The process provides direction on how distribution operators and troublemen can use fault indicators and line sensors to help reduce the patrol footprint.

The Number of Circuit Miles Capable of These Settings

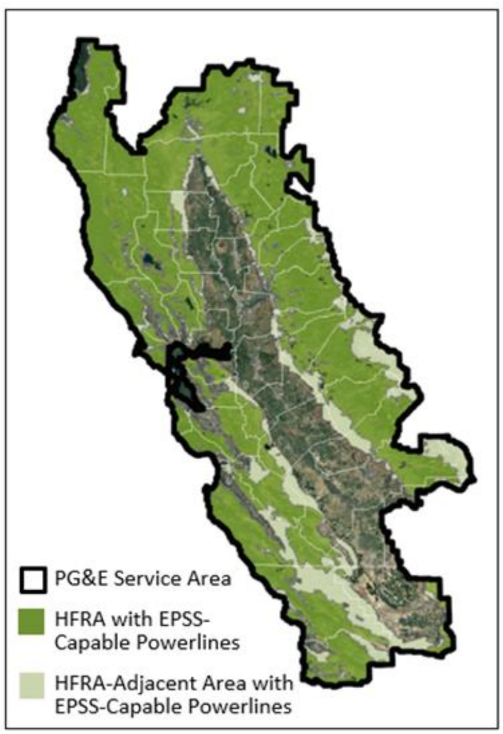
In 2022, we expanded the scope of EPSS to all HFRAs in our service territory and select adjacent EPSS buffer areas. Table PG&E-8.1.8-2 summarizes the number and location of EPSS-capable miles.

TABLE PG&E-8.1.8-2:
SUMMARY OF EPSS CAPABLE MILES

Mile Type	Miles
HFRA	25,236
EPSS Buffer Areas	9,596
Additional Miles (e.g., miles outside of HFRA or Buffer Areas electrically connected to an EPSS-capable device)	9,240
Total	44,072

In total, 4,830 distribution line protection devices—which includes 3,597 in HFRA areas and 1,233 in EPSS buffer zones—were engineered to provide EPSS protection. Protection devices on another 47 transmission circuits were also engineered to provide EPSS protection. A map of EPSS-capable miles across our service territory can be seen in Figure PG&E-8.1.8-3 below.

FIGURE PG&E-8.1.8-3:
EPSS CAPABLE SERVICE TERRITORY MAP

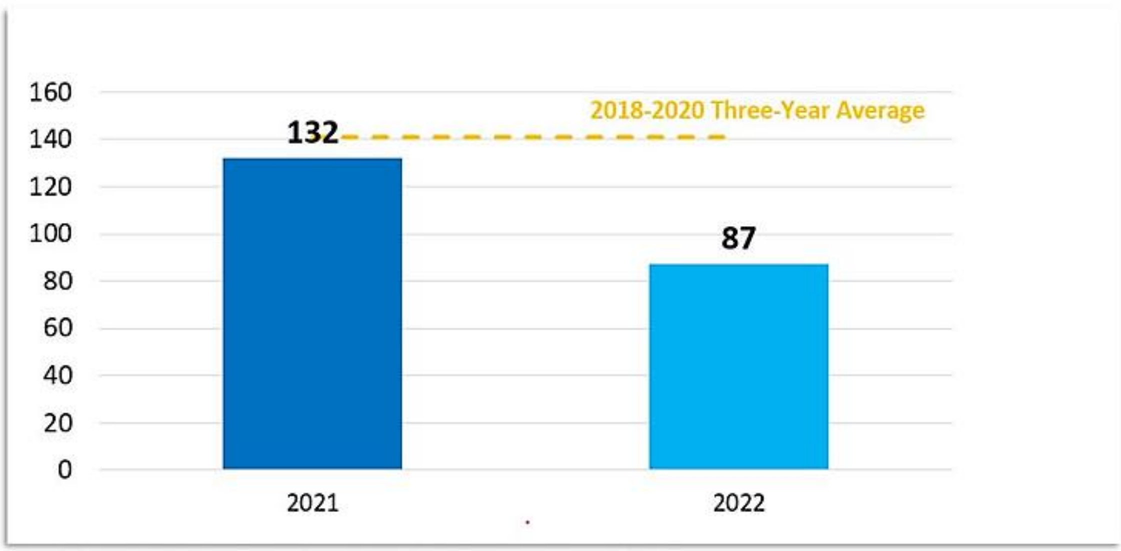


In 2023, we will continue to provide this level of EPSS protection capability on all 796 HFRA distribution circuits and 210 EPSS buffer zone distribution circuits. We will also examine the potential to expand protection on transmission circuits. PG&E's electric grid is not static and is subject to adjustments where needed. As a result, a change control process was established and will be used when device and circuit updates are required as the program continues to evolve and mature.

An Estimate of the Effectiveness of the Settings

Through December 31, 2022, there was a greater than 36 percent reduction in CPUC-reportable ignitions in HFTD-areas compared to the overall 2018-2020 average. This can be seen in Figure PG&E-8.1.8-4 below.

FIGURE PG&E-8.1.8-4:
CPUC REPORTABLE IGNITIONS IN HFTDS



Data as of December 31, 2022. Excludes 2022 HFTD RFIs currently under review. Ignitions data is preliminary and subject to change.

This is primarily driven by a 68 percent reduction in CPUC-reportable ignitions on EPSS-enabled lines in HFTD-areas (compared to weather-normalized 2018-2020 average ignitions).

Along with the significant reduction of overall ignition count, we have also observed a dramatic decrease in total HFTD acres burned. In 2022 we observed a 99 percent decrease in total HFTD acres burned relative to the 2018-2020 average. A primary driver for this is understood to be the reduced fault energy that occurs when EPSS protection is enabled.

These results highlight the significant impact EPSS has had on eliminating the occurrence of ignitions and reducing fire size when they do occur.

8.1.8.1.2 Automatic Recloser Settings

Settings 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 for sustained outages. Reclosing devices can automatically re-energize lines to restore service when momentary fault conditions occur.

Analysis of Reliability/Safety Impacts for Settings the Electrical Corporation Uses

We have conducted extensive analysis on the reliability impacts of the settings we use. (See Section 8.1.8.1.1).

Criteria for When the Electrical Corporation Enables the Settings

The action of reclosing can pose a risk of fire ignition during elevated fire conditions. In 2022, we aligned the disablement of automatic reclosing of protection devices with the enablement of EPSS on the distribution system.

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 8.1.8.1.1. 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

The operational procedures for disabling reclosers as a component of EPSS enablement is described in Section 8.1.8.1.1.

The Number of Circuit Miles Capable of These Settings

All EPSS-capable lines have automatic recloser settings. See Table PG&E-8.1.8-2 above for more information.

An Estimate of the Effectiveness of the Settings

The effectiveness of automatic recloser settings as a component of our EPSS Program is described in Section 8.1.8.1.1.

8.1.8.1.3 Settings of Other Emerging Technologies (e.g., Rapid Earth Fault Current Limiters)

8.1.8.1.3.1 Rapid Earth Fault Current Limiter

Settings 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. 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

REFCL is still in the pilot, testing and demonstration phase, at only our Calistoga substation. 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.

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

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

We do not currently plan to install any additional REFCL systems. We will resume staged fault testing of the REFCL installation at the Calistoga substation in 2023 to complete additional pilot evaluation. If this is successful, we will continue to evaluate REFCL, including whether any additional sites are appropriate for future installations. REFCL protects the approximately 160 primary distribution circuit miles fed from the Calistoga substation.

An Estimate of the Effectiveness of the Settings

The fault energy measured for sustained low impedance faults with REFCL active was fewer than 10 percent of the fault energy with EPSS settings and solid grounding. The distribution system was able to ride through momentary staged faults. Further tests and evaluations are ongoing at the demonstration site.

8.1.8.1.3.2 Pole Mounted Sensor

Settings to Reduce Wildfire Risk

We are evaluating two sensor technologies. One sensor technology consists of a small computer integrated with a collection of sensors powered by a battery and solar panel. Installation of these sensors onto powerline poles could help reduce wildfire risk in different ways that could lead to an ignition. The second technology is a smart tape that could be applied to poles and conductors to provide location and fault characteristic data to support patrol and restoration. (See Section 8.1.8.1.3.3 below.) These technologies could detect vegetation contacting a line, downed lines, or arc flashes. They can also help us monitor the status of nearby vegetation for trimming, provide data to support secondary causal evaluation patrols on unknown outage causes, and provide weather condition data to determine wildfire risk.

These sensors use a variety of communication options including cellular, satellite, and radio. Currently, PG&E electrically monitors its system in a continual manner (i.e., current and voltage). This new sensor would allow us to monitor the system mechanically (i.e., vibrations, acoustics, infrared light, and visible light) if installed directly onto powerline poles.

Analysis of Reliability/Safety Impacts for Settings the Electrical Corporation Uses

The pole mounted sensor is still in the testing and demonstration phase. At this time, reliability and safety impacts for these settings cannot be confirmed.

Criteria for When the Electrical Corporation Enables the Settings

The pole mounted sensor would constantly monitor activity on the poles on which they are installed.

Operational Procedures for When the Settings Are Enabled

The operational procedures for when the pole mounted sensor is used have not yet been determined because they are still in the testing and demonstration phase.

The Number of Circuit Miles Capable of These Settings

Currently, PG&E does not have any devices installed on our system. We are currently developing the pilot plan for the pole mounted sensor on a limited number of circuits that have experienced poor reliability and our project scope is under development.

An Estimate of the Effectiveness of the Settings

Estimates of the effectiveness of the pole mounted sensor are not yet available until further testing and evaluation is completed.

8.1.8.1.3.3 Smart Tape

Settings to Reduce Wildfire Risk

We are working with a third party to evaluate a "smart tape" that can be placed on our equipment that provides data to help us restore power more quickly. Following an outage on an EPSS-enabled circuit, this technology could help us:

- Locate faults and determine outage causes faster;
- Reduce outage durations for customers; and
- Identify issues that can be addressed with mitigations strategies to prevent future outages.

Through a pilot effort, we will evaluate the effectiveness of this tape, which can be wrapped around individual conductors, poles or cross-arms and create its own communication mesh network for long distance data transfer. This tape would harvest power from the attached conductor via electromagnetic induction so no wiring connection to the conductors is required. The tape could function in areas where sunlight is minimal and solar powered sensors would not be feasible.

Analysis of Reliability/Safety Impacts for Settings the Electrical Corporation Uses

This tape is still in development and has yet to be tested on our electric grid. At this time, reliability and safety impacts for this technology cannot be confirmed.

Criteria for When the Electrical Corporation Enables the Settings

The criteria for when this tape would be used have not yet been determined.

Operational Procedures for When the Settings Are Enabled

This tape is still in development and has yet to be tested on our electric grid. The operational procedures for when this tape is in use have not yet been determined.

The Number of Circuit Miles Capable of These Settings

No circuit miles currently have this tape installed as it is still in the development phase.

An Estimate of the Effectiveness of the Settings

Estimates of the effectiveness of this tape are not yet available until further development, testing and evaluation is completed.

8.1.8.2 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, at a minimum, how the electrical corporation:

- *Locates the issues;*
- *Prioritizes the issues;*
- *Notifies relevant personnel and suppression resources to respond to issues; and*
- *Minimizes/optimizes response times to issues.*

PG&E uses an Operational Mitigation, EPSS (see Section 8.1.8.1), to respond to faults, ignitions, and other issues detected on the grid that may result in a wildfire. The enablement criteria for EPSS are conservative, thus putting any circuit that could experience dangerous conditions into EPSS mode. EPSS covers all HFRA and our buffer zone. Any fault that may result in a wildfire is therefore managed by EPSS protocols. In addition to EPSS, we rely on PSPS during severe weather events to address issues that may result in a wildfire (see Section 9).

PG&E enables EPSS protection settings during elevated fire conditions in the HFRA to quickly de-energize a powerline when a fault occurs that could cause an ignition. These are faults that occur due to vegetation falling on a line, animals contacting the conductor, equipment failures, or from third-party contact. In the following section, we describe our processes to identify those types of faults and dispatch personnel to address them, as outlined in the PG&E Infrared (IR) Inspections of Electric Distribution Facilities Procedure (TD-2202P-01) in Appendix E.

Locates the Issues

PG&E's Emergency Operations Restoration Dispatch Supervisor and dispatch personnel monitor the Outage Information System/Outage Management Tool to ensure personnel are dispatched quickly to respond 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

An EPSS outage is considered a priority as a potential ignition source given the elevated fire risk that associated with EPSS enablement. EPSS outages must be responded to within 60 minutes to determine whether an ignition has occurred.

Notifies Relevant Personnel & Suppression Resources to Respond to the Issues

The Infrared (IR) Inspections of Electric Distribution Facilities Procedure (TD-2202P-01) outlines a resource availability order that dispatch must use for deploying resources to respond to an EPSS outage during normal business hours. The first priority is sending a troubleman from the yard nearest the ignition. If a troubleman is unavailable, then a Safety and Infrastructure Protection Team (SIPT) crew will respond if available. If neither a troubleman nor SIPT crew can respond within 60 minutes, then 10 other employee groups have been identified that can 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.[133]

Minimizes/Optimizes Response Times to Issues

PG&E optimizes our response time to unplanned EPSS outages by targeting a response within 60 minutes using the closest available resources.

8.1.8.3 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; and
  - How it notifies personnel when conditions change, warranting implementation of those procedures.
- *The electrical corporation's procedures regarding 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.*

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[133] See Assembly Bill 2380 (Reg. Sess. 2017-2018), Chapter 636.

What Type of Work Is, or Is Not, Allowed During Each Level of Risk

PG&E's Preventing and Mitigating Fires While Performing PG&E Work Standard (TD-1464S) (see Appendix E) 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 Mitigation Checklist that crews use before beginning work to ensure all the preventative measures within the matrix and standard are in place.

The Wildfire 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. The PG&E Preventing and Mitigating Fires While Performing PG&E Work Standard (TD-1464S) is also consistent with all requirements included in the Public Resources Code (PRC).[134]

How PG&E Defines Each Level of Wildfire Risk

PG&E uses a Utility FPI Rating System to determine the risk of fire and its likely behavior. The scale, from "R1" to "R5-Plus," considers fuel moisture, humidity, wind speed, air temperature, and historical fire occurrence. The rating and their definitions are shown in Table PG&E-8.1.8-3 below.

TABLE PG&E-8.1.8-3:
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 the 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, "plus" there are high risk weather triggers (e.g., strong winds).

[134] PRC, Sections 4421-4446.

How the Electrical Corporation Trains its Personnel on Those Procedures

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. The course covers:

- The FPI daily forecast;
- How to consult the Wildfire Mitigation Matrix and the Wildfire Risk Checklist to apply mitigation strategies according to the FPI rating;
- How to prepare for work by implementing required mitigation strategies and adjust if FPI ratings or weather conditions change; and
- How to use fire mitigation tools.

How the Electrical Corporation Notifies Personnel When Conditions Change, Warranting Implementation of Those Procedures

A PG&E Utility FPI Forecast email 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 email when applicable.

It is the responsibility of any person in charge of personnel working in a FPI Rating Area to be aware of changing local meteorological conditions. The person in charge must also be aware of the possibility of increased fire potential during the time work is in progress. Utility Standard TD-1464S provides details on fire precautions and restrictions in hazardous FPI rating areas.

The Electrical Corporation's Procedures Regarding Deployment of firefighting Staff and Equipment (e.g., Fire Suppression Engines, Hoses, Water Tenders, Etc.) to Construction and/or Electrical Worksites for Site-Specific Fire Prevention and Ignition Mitigation During On-Site Work

Utility Standard TD-1464S 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 TD-1464S 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 International Brotherhood of Electrical Workers represented employees 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.

PG&E is exploring the possibility of dedicating one PG&E-owned Heavy-Lift Sikorsky UH60 helicopter to support wildfire risk reduction in the PG&E territory. We would provide the PG&E-owned helicopter to local counties due to the limited availability of fire suppression resources statewide. We are also looking into providing sustainable funding to contract aerial firefighting resources through a pilot project referred to as the Initial Fire Attack Program. This pilot program would work with various counties within our territory.

The Initial Fire Attack Program allows PG&E to work with local agencies in order to be the first responder on the scene of a wildfire ignition. In 2022, PG&E funded the purchase and installation of a Simplex internal tank system on one of PG&E's heavy-lift helicopters. The tank system allows the heavy-lift helicopter to conduct fire suppression over congested areas in accordance with Federal Aviation Administration (FAA) regulations, reducing dispatch time. The internal system can carry up to 1,000 gallons of water or retardant. PG&E plans to continue exploring how we can contract with local agencies and county fire agencies to provide additional firefighting support during the wildfire season.

8.1.9 Workforce Planning

In this section, the electrical corporation must report on qualifications and training practices regarding wildfire and PSPS mitigation for workers in the following target roles:

- *Asset inspections;*
- *Grid hardening; and*
- *Risk event inspection.*

Table 8-9, Table 8-10, and Table 8-11 are examples of the required information.

For each of the target roles listed above, the electrical corporation must:

- *List all worker titles relevant to the target role.*
- *For each worker title, list and explain minimum qualifications, with an emphasis on qualifications relevant to wildfire and PSPS mitigation. Note if the job requirements include:*
  - *Going beyond a basic knowledge of General Order (GO) 95 requirements to perform relevant types of inspections or activities; and*
  - *Being a "Qualified Electrical Worker" (QEW); if so, define what certifications, qualifications, experience, etc. are required to be a QEW for the target role for the electrical corporation.*
- *Report the percentage of electrical corporation and contractor full-time employees (FTE) in the target role, with specific job titles; and*
- *Report plans to improve qualifications of workers relevant to wildfire and PSPS mitigation work. The electrical corporation must explain how it is developing training programs that teach electrical workers to identify hazards that could ignite wildfires.*

Table 8-9, Table 8-10, and Table 8-11 are examples of the required information.

8.1.9.1 Workforce Planning – Asset Inspections

- **Utility Initiative Tracking ID:** AI-01

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 for PG&E. Table 8-9 below provides:

- *A list of all worker titles relevant to a target role;*

- *The minimum qualifications for each of those titles;*
- *The percentage of FTEs in a target role; and*
- *The percentage of FTEs with these minimum qualifications.*

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. Our training program incorporates updates and changes to the Inspect Application tool so that inspectors are well qualified to document and prioritize corrective actions. Updates to training programs also includes a review of QV findings from previous year(s) inspections and, where applicable, we update the training to improve inspection quality.

TABLE PG&E-8-9:
WORKFORCE PLANNING, ASSET INSPECTIONS

Worker Title	Minimum Qualifications for Target Role	Special Certification Requirements	Electrical Corporation PG&E % FTE Min Quals[a]	Electrical Corporation PG&E % Special Certifications	Contractor % FTE Min Quals[a]	Contractor % Special Certifications	Reference to Electrical Corporation Training/Qualification Programs
Compliance Inspector	QEW Consisting of Journeyman Lineman and New Inspector Training	Compliance Inspector Training Course	62%	N/A	77%	N/A	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	2%	N/A	0%	N/A	ELEC-1000 (Initial) TECH-0020 (Refresher) ELEC-0340 (CONT) ELEC-0341 (CONT) ELEC-0342 (CONT)
Transmission Trouble man	QEW Consisting of Journeyman Lineman and New Inspector Training	N/A – Nothing beyond QEW	10%	N/A	18%	N/A	PSOS-0410 (CONT) PSOS-0451 (CONT) PSOS-0452 (CONT)
Transmission Towerman	QEW Consisting of Journeyman Lineman and New Inspector Training	N/A – Nothing beyond QEW	13%	N/A	1%	N/A	PSOS-0480

TABLE PG&E-8-9:
WORKFORCE PLANNING, ASSET INSPECTIONS
(CONTINUED)

Worker Title	Minimum Qualifications for Target Role	Special Certification Requirements	Electrical Corporation PG&E % FTE Min Quals(a)	Electrical Corporation PG&E % Special Certifications	Contractor % FTE Min Quals(a)	Contractor % Special Certifications	Reference to Electrical Corporation Training/Qualification Programs
Inspection Review Specialist, Senior	QEW Consisting of Journeyman Lineman and New Inspector Training	N/A – Nothing beyond QEW	5%	N/A	1%	N/A	ELEC-1000 (Initial) TECH-0020 (Refresher) ELEC-0340 (CONT) ELEC-0341 (CONT) ELEC-0342 (CONT)
Inspection Review Specialist, Expert	QEW Consisting of Journeyman Lineman and New Inspector Training	N/A – Nothing beyond QEW	8%	N/A	3%	N/A	ELEC-1000 (Initial) TECH-0020 (Refresher) ELEC-0340 (CONT) ELEC-0341 (CONT) ELEC-0342 (CONT)
Total			100%		100%		

(a) All PG&E employees and contractors meet the minimum qualifications for the assigned role.

8.1.9.2 Workforce Planning – 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 8-10 includes the resource workforce composition for both contracted and internally resourced grid hardening projects.

Worker Titles Relevant to the Target Role

Please refer to Table 8-10 below.

Minimum Qualifications

Please refer to Table 8-10 below for details by each worker title.

Related Trainings for Wildfire and PSPS Mitigation

PG&E continues our training program for QEW workers focused on inspecting, patrolling, and reporting findings which supports wildfire mitigation. The following trainings are provided to PG&E employees.

- PSOS-0481 Transmission System Inspections-Ground: This training focuses on the overhead portion of the Electric Transmission Line Inspection and Preventive Maintenance (ETPM) Program manual for all personnel responsible for patrol, inspection, and maintenance of the overhead, underground, and tower electric transmission line systems. It provides training in understanding how to apply general inspection and patrol procedures at electric transmission facilities.

- PSOS-0452 System Inspection Electric Transmission Ground-Mobile:[135] This training focuses on teaching the learners to use the Inspect Ap software to record inspections. It walks the trainees through all Transmission Inspection workflows in the mobile application.

- ELEC-0417 Transmission Patrols and Inspections: This training helps employees identify and document abnormal conditions and prioritize the corrective actions required, as well as describe and comply with the patrol and inspection procedures for Overhead, Underground, Infrared (IR), and Maintenance.

- PSOS-0480 Transmission System Inspections-Climbing: This training focuses on the tower sections of the ETPM manual for all personnel responsible for patrol, inspection, and maintenance of the overhead, underground, and tower electric transmission line systems to understand how to apply general inspection and patrol procedures at the electric transmission facilities.

[135] PSOS-0452 is available for both employees and contractors.

- SAFE-0256 Aerial Patrol: This training prepares linemen, troublemen, and pilots to work together as a team so they can avoid hazards while patrolling in the utility environment.

The following trainings are available for contractors:

- PSOS-0410 System Inspections Electric Transmission Ground Contractor Onboarding: This training prepares external contractors to perform enhanced and accelerated Tier 2-3 overhead transmission line inspections in accordance with PG&E expectations.

- PSOS-0451 System Inspections Electric Transmission Ground Contractor Process: This training focuses on the overhead portion of the Electric Transmission Line Inspection and Preventive Maintenance (ETPM) Program manual for all personnel responsible for patrol, inspection, and maintenance of the overhead, underground, and tower electric transmission line systems to understand how to apply general inspection and patrol procedures at electric transmission facilities.

Additional Knowledge Based on GO 95 Requirements to Perform Relevant Types of Inspections or Activities

PG&E workers adhere to the Book of Standards and bulletins that provide updated standards in the Technical Information Library. At times, the standards go beyond GO 95, including:

- More stringent requirements based on time and locations where insulation contaminations can occur;

- Additional covering on devices/insulators due to coastal and winter ground fog; and

- Additional evaluation of materials for industrial contamination based on region.

Minimum Qualifications for QEW in a Target Role for Electrical Corporation

The Lineman and foreman roles are Qualified Electric Worker (QEW) status. To perform grid hardening work, at least one worker on-site must be a QEW. In some instances, work can be performed by various non-QEWs roles, but the work is always 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 4-year apprentice program that requires written, hands-on technical, and physical tests, and provides superior on the on-the-job training. The ALP center, located at the Livermore Electric Safety Academy in Livermore, California, has field training coordinators who monitor the successful progression of apprentice lineman to journeyman lineman.

Percentage of Electrical Corporation and Contractor FTEs in the Target Role, and Titles

Please refer to Table 8-10 below for details. The percentages provided in the table reflect the percentage of total workers in the target role.

Plans to Improve Qualifications of Workers Relevant to Wildfire, PSPS Mitigation Work

PG&E continues to train all general construction coworkers in fire ignition safety while working on our facilities. This includes using water buffaloes and water back-packs and looking for stale/outdated hardware among other work. Employees are also trained on how to review fire index ratings prior to working in a specific area. In addition, they are instructed on and how to write an EC tag if safety issues are identified.

PG&E is not planning any significant improvements to qualifications or training requirements to address wildfire and PSPS mitigation work. Enhancements to training will be implemented based on changes to processes and procedures or in response to any lessons learned or gaps identified.

TABLE 8-10:
WORKFORCE PLANNING, GRID HARDENING

Worker Title	Minimum Qualifications for Target Role	Special Certification Requirements/ Qualifications	Electrical Corporation PG&E % FTE Min. Qualifications[(a)]	PG&E Electrical Corporation% Special Certifications	Contractor % FTE Min. Qualifications[(a)]	Contractor % Special Certifications	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)	N/A	N/A	7%	8%	Electrical Corporation: Required Trainings relevant to Wildfire and PSPS (see list 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)	13%	31%	12%	14%	See above

TABLE 8-10:
WORKFORCE PLANNING, GRID HARDENING
(CONTINUED)

Worker Title	Minimum Qualifications for Target Role	Special Certification Requirements/ Qualifications	Electrical Corporation PG&E % FTE Min. Qualifications[(a)]	PG&E Electrical Corporation% Special Certifications	Contractor % FTE Min. Qualifications[(a)]	Contractor % Special Certifications	Reference to Electrical Corporation Training/ Qualification Programs
Lineman (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)	18%	44%	24%	28%	See above
Apprentice Lineman	18 years of age or older High School Diploma or GED Successful passing of the ALP and 3-day climbing 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	26%	N/A	14%	N/A	See above

TABLE 8-10:
WORKFORCE PLANNING, GRID HARDENING
(CONTINUED)

Worker Title	Minimum Qualifications for Target Role	Special Certification Requirements/ Qualifications	Electrical Corporation PG&E % FTE Min. Qualifications[a]	PG&E Electrical Corporation% Special Certifications	Contractor % FTE Min. Qualifications[a]	Contractor % Special Certifications	Reference to Electrical Corporation Training/ Qualification Programs
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	N/A	N/A	11%	13%	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	13%	N/A	N/A	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	13%	N/A	N/A	N/A	See above

TABLE 8-10:
WORKFORCE PLANNING, GRID HARDENING
(CONTINUED)

Worker Title	Minimum Qualifications for Target Role	Special Certification Requirements/ Qualifications	Electrical Corporation PG&E % FTE Min. Qualifications[(a)]	PG&E Electrical Corporation% Special Certifications	Contractor % FTE Min. Qualifications[(a)]	Contractor % Special Certifications	Reference to Electrical Corporation Training/ Qualification Programs
Cable Splicers	18 years of age or older High School Diploma or GED Valid CA Class C driver's license (or higher) 2 years' experience as Journey Cable Splicer	IBEW journeyman card for Cable Splicer or State JATC certification 40-hour Switchman Training Certification / Card	10%	25%	N/A	N/A	See above
Apprentice Cable Splicer	Valid Class C California driver's license	N/A	7%	N/A	N/A	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	N/A	N/A	22%	25%	See above
Civil Crew Inspector	Valid Class C California driver's license	OSHA 10	N/A	N/A	10%	11%	See above
Total			100%	100%	100%	100%(b)	

(a) All PG&E and contract employees meet the minimum qualifications for performing the assigned role.
(b) Values shown in column sum to 99 percent due rounding.

8.1.9.3 Workforce Planning – Risk Event Inspection

Overview

Table 8-11 includes Workforce Planning information for Risk Event Inspection.

Plans to Improve Worker Qualifications

No material improvements have been identified at this time. Enhancements to training will be implemented based on changes to processes and procedures or in response to any lessons learned or identified gaps.

TABLE 8-11:
WORKFORCE PLANNING, RISK EVENT INSPECTION

Worker Title	Minimum Qualifications for Target Role	Special Certification Requirements	PG&E % FTE Min Quals[(a)]	PG&E % Special Certifications	Contractor % FTE Min Quals[(a)]	Contractor% Special Certifications	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	86%	N/A – Nothing beyond QEW	(b)	(b)	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.
Cablemen 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	14%	N/A – Nothing beyond QEW	(b)	(b)	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.
Total			100%				

(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.

8.2 Vegetation Management and Inspections

8.2.1 Overview

In accordance with Public Utilities Code Section 8386I(9), each electrical corporation's Wildfire Mitigation Plan (WMP) must include plans for Vegetation Management (VM).

In this section, the electrical corporation must identify objectives for the next 3- and 10-year periods, targets, and performance metrics related to the following VM programmatic areas:

- *Vegetation inspections;*
- *Vegetation and fuels management;*
- *VM enterprise system;*
- *Environmental compliance and permitting;*
- *Quality Assurance/Quality Control (QA/QC);*
- *Open work orders; and*
- *Workforce planning.*

PG&E's Vegetation Management (VM) team works with our customers and communities to manage trees and other vegetation located near powerlines that could cause a wildfire or power outage. Each year we inspect approximately 100,000 miles of powerlines, trim or remove more than 1 million trees, and address dead and dying trees.

In this WMP PG&E is introducing three new programs: Vegetation Management for Operational Mitigations; Tree Removal Inventory; and Focused Tree Inspections. Details about these PG&E programs are provided in Sections 8.2.2.2.3, 8.2.2.2.4, and 8.2.2.2.5. As PG&E increases undergrounding efforts, vegetation work and the associated costs can be reduced and, for some circuit segments, eliminated. Other programs that mitigate vegetation risk to facilities include the use of overhead hardening or remote grids.

Other critical elements of our VM Programs include developing and implementing robust inspection protocols by updating our standards, procedures, training programs, and QA/QC programs.

- Vegetation Inspections: Vegetation inspection is necessary to comply with CPUC, PRC, and North American Electric Reliability Corporation (NERC) regulatory requirements and our internal procedures. Accordingly, we have developed an annual inspection cycle program as part of our overall Transmission, Distribution, and Substation VM programs;

- Transmission: Transmission programs include Routine NERC and Routine Non-NERC. These Routine programs recur annually, with the Integrated Vegetation Management (IVM) Program recurring according to the vegetation growth response. PG&E's Transmission vegetation inspection capabilities use technologies such as Light Detection and Ranging (LiDAR). See Section 8.2.2.1 for more information;

- Distribution: Distribution programs include Routine patrols which occur annually, and Second Patrol which occurs approximately six months offset from Routine patrols. See Section 8.2.2.2;

- Substations: PG&E assesses the area around Electric Transmission (ET) Substations in High Fire Threat District (HFTD) and High Fire Risk Area (HFRA) areas to identify potential flammable fuels and vegetation for removal. This minimizes the potential for ignition spread outside of facilities and provides improved structure defense capability for firefighting by ensuring there is a safe distance between vegetation and critical infrastructure. See Section 8.2.2.3;

- Vegetation and Fuels Management: PG&E's VM has various programs supporting vegetation and fuels management activities. See Section 8.2.3;

- VM Enterprise System: PG&E's VM teams currently use multiple centrally managed systems via various platforms to capture inspection, trimming, and removal activities. The VM Technology team is implementing a multi-year project to centralize these activities into a single software platform. See Section 8.2.4;

- Environmental Compliance and Permitting: See Section 5.4.5;

- Quality Assurance/Quality Control: PG&E's VM Quality Team encompasses Quality Assurance (QA), Quality Verification (QV), and Quality Control (QC), See Section 8.2.5;

- Open Work Orders: PG&E's VM teams manage work processes through Standards and Procedures. In addition, a centralized Constraints Management Team is being built out to support all VM Programs. See Section 8.2.6; and

- Workforce Planning: PG&E's VM team works internally and with contract vendors to ensure a qualified workforce in both inspection and project roles. See Section 8.2.7.

8.2.1.1 Objectives

Each electrical corporation must summarize the objectives for its 3-year and 10-year plans for implementing and improving its VM and inspections. These summaries must include the following:

- *Identification of which initiative(s) in the WMP the electrical corporation is implementing to achieve the stated objective, including Utility Initiative Tracking IDs;*
- *Reference(s) to applicable codes, standards, and best practices/guidelines and an indication of whether the electrical corporation exceeds an applicable code, standard, or regulation;*
- *Method of verifying achievement of each objective;*
- *A completion date for when the electrical corporation will achieve the objective; and*
- *Reference(s) to the WMP section(s) or appendix, including page numbers, where the details of the objective(s) are documented and substantiated.*

This information must be provided in Table 8-*12 for the 3-year plan and Table 8-13 for the 10-year plan.*

- Table 8-12 and Table 8-13 Information Summary: In Table 8-12 and Table 8-13, we are providing the objective name (Objective Name), a description of the objective (Objective Description), the anticipated outlook of the objective (3-Year/10-Year Outlook), the planned due date for the objective (Completion Date), the applicable Initiative Tracking ID (Initiative Tracking ID), "Applicable Regulations, Codes, Standards, and Best Practices", "method of verification", and "section and page #" references. As noted in Section 7.2.1, "Applicable Regulations, Codes, Standards, and Best Practices", "method of verification", and "section and page #" columns are not a part of the objective. Instead, the controlling objective information is in the "Objective Description" and "Completion Date" columns.
- Reporting: Unless changed through Energy Safety's Change Order process, PG&E will use the objectives in Table 8-12 and Table 8-13 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 2023-2025 WMP, we discuss current plans for wildfire-related activities beyond the objectives in Table 8-12 and Table 8-13. The timing and scope of these additional activities and work may change. We will not be reporting on these plans or activities in our QDR, QN, or ARC because they are not objectives but are descriptions of plans and activities in our 2023-2025 WMP to provide a complete picture of our wildfire mitigation activities.
- External Factors: All objectives in the below Table 8-12 and Table 8-13 are subject to External Factors which represent reasonable circumstances which may impact execution against objectives including, but not limited to, physical conditions, landholder refusals, environmental delays, 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 ID: We are including Initiative Tracking IDs in each section that has associated objectives. Table 8-12 and Table 8-13 display the Tracking IDs we are implementing to tie the objectives to the narratives and initiatives in the WMP. The Initiative Tracking IDs will also be used for reporting in the QDR. For any initiative without an objective, we have not included an Initiative Tracking ID.

TABLE 8-12:
VEGETATION MANAGEMENT IMPLEMENTATION OBJECTIVES (3-YEAR PLAN)

Objective Name	Objective Description[(a)]	Applicable Initiative(s), Tracking ID(s)	Applicable Regulations, Codes, Standards, and Best Practices (See Note)	Method of Verification (i.e., program)	Completion Date	Reference (Section and Page #)
Focused Tree Inspection Program	1. Identify the Areas of Concern (AOC) by developing a collaborative, cross-functional team to evaluate the service territory with electric overhead assets and create system wide map that includes Vegetation Management AOCs. 2. Initiate a pilot program in at least one AOC. 3. Fully implement AOC cross-functional team to implement guidelines across all AOCs. Determine value of a multi-year historical tree data set.	VM-03	GO 95, Rule 35 GO 95, Rule 35 Appendix E GO 95, Rule 18 PRC 4293 and 4295.5 CCR Title 14 Sections 1250, 1251, 1252, 1253, 1256, 1257 and 1258 ANSI A300	1. Detailed County Level Assessments and Areas of Concern will be updated in GIS database. A report that outlines the methodology of the cross-functional team approach. 2. Documentation of pilot program inspections in VM system of record. 3. Document the value of a multi-year historical tree data set.	1. 12/01/2023 2. 12/01/2023 3. 12/31/2025	Section 8.2.2.2.5 Page 529

TABLE 8-12:
VEGETATION MANAGEMENT IMPLEMENTATION OBJECTIVES (3-YEAR PLAN)
(CONTINUED)

Objective Name	Objective Description[a]	Applicable Initiative(s), Tracking ID(s)	Applicable Regulations, Codes, Standards, and Best Practices (See Note)	Method of Verification (i.e., program)	Completion Date	Reference (Section and Page #)
Constraint Resolution Procedural Guideline	Develop a process of centralizing constraints resolution. As part of the build out of the centralized constraints team, three major categories will be addressed: customer constraints, environmental constraints (including internal PG&E procedures required to perform work) and permitting constraints (including both Land and Environmental permits). For each major constraint category build a process for addressing each constraint type, implement the new process, and create metrics to track each constraint type. Reporting will track total constraints by type and the time it takes to resolve a constraint after it has been identified. PG&E will consider creating a "right tree-right place" program, as part of the centralize Constraints Resolution process.	VM-09	GO 95, Rule 35 GO 95, Rule 35 Appendix E GO 95, Rule 18 PRC 4293 and 4295.5 CCR Title 14 Sections 1250, 1251, 1252, 1253, 1256, 1257 and 1258 ANSI A300	1. Procedural guideline and evaluation of a "right tree-right place" program. 2. Reports from VM system of record demonstrating added constraints tracking functionality.	1. 12/31/2023 2. 12/31/2025	Section 8.2.6 Page 556 ACI PG&E 22-25 Page 938

(a) While not a defined objective, PG&E will continue to address risk through our compliance work as well as other mitigation measures including operational mitigations, Public Safety Power Shutoff (PSPS), and Enhanced Powerline Safety Settings (EPSS).

TABLE 8-13:
VEGETATION MANAGEMENT IMPLEMENTATION OBJECTIVES (10-YEAR PLAN)

Objective Name	Objective Description[(a)]	Applicable Initiative(s), Tracking ID(s)	Applicable Regulations, Codes, Standards, and Best Practices (See Note)	Method of Verification (i.e., program)	Completion Date	Reference (Section and Page #)
Inspection in HFTD and HFRA supporting key vegetation management initiatives	Continue multiple inspection activities in HFTD and HFRA supporting key vegetation management initiatives	VM-10	GO 95, Rule 35 GO 95, Rule 35 Appendix E GO 95, Rule 18 PRC 4293 and 4295.5 CCR Title 14 Sections 1250, 1251, 1252, 1253, 1256, 1257 and 1258 ANSI A300	VM Database	12/31/2032	Section 8.2.2 Page 510
Enhance and refine Focus Tree Inspection – Areas of Concern (AOC)	Enhance and refine Focus Tree Inspection - Areas of Concern (AOC) development criteria and application of the AOCs to vegetation management programs	VM-11	GO 95, Rule 35 GO 95, Rule 35 Appendix E GO 95, Rule 18 PRC 4293 and 4295.5 CCR Title 14 Sections 1250, 1251, 1252, 1253, 1256, 1257 and 1258 ANSI A300	Documentation describing our efforts to enhance and refine the program	12/31/2032	Section 8.2.2.2.5 Page 529

TABLE 8-13:
VEGETATION MANAGEMENT IMPLEMENTATION OBJECTIVES (10-YEAR PLAN)
(CONTINUED)

Objective Name	Objective Description[(a)]	Applicable Initiative(s), Tracking ID(s)	Applicable Regulations, Codes, Standards, and Best Practices (See Note)	Method of Verification (i.e., program)	Completion Date	Reference (Section and Page #)
Evaluate emerging technologies	Evaluate emerging technologies to enhance focus of and streamline execution of vegetation management inspections	VM-12	GO 95, Rule 35 GO 95, Rule 35 Appendix E GO 95, Rule 18 PRC 4293 and 4295.5 CCR Title 14 Sections 1250, 1251, 1252, 1253, 1256, 1257 and 1258 ANSI A300	Documentation describing our evaluation of emerging technologies	12/31/2032	Sections 8.2.2.1 and 8.2.2.2 Page 514 and Page 523

(a) While not a defined objective, PG&E will continue to address risk through our compliance work as well as other mitigation measures including operational mitigations, Public Safety Power Shutoff (PSPS), and Enhanced Powerline Safety Settings (EPSS).

8.2.1.2 Targets

Initiative targets are forward-looking quantifiable measurements of activities identified by each electrical corporation in its WMP. Electrical corporations will show progress toward completing targets in subsequent reports, including QDRs and WMP Updates.

The electrical corporation must list all targets it will use to track progress on its VM and inspections for the three years of the Base WMP. Office of Energy Infrastructure Safety (Energy Safety) Compliance Assurance Division and third parties must be able to track and audit each target. For each initiative target, the electrical corporation must provide the following:

- *Utility Initiative Tracking IDs;*
- *Projected targets for each of the three years of the Base WMP and relevant units;*
- *Quarterly, rolling targets for 2023 and 2024 (inspections only);*
- *The expected "x% risk impact." For each of the three years of the Base WMP. The expected x% risk impact is the expected percentage risk reduction per year, as described in Section 7.2.2.2; and*
- *Method of verifying target completion.*

The electrical corporation's targets must provide enough detail to effectively inform efforts to improve the performance (i.e., reduction in ignition probability or wildfire consequence) of the electrical corporation's VM and inspections initiatives.

Table 8-14 and Table 8-15 provide examples of the minimum acceptable level of information.

- Table 8-14 Information Summary: In Table 8-14, we are providing the target name and ID (Target Name), the applicable Initiative Tracking ID (Initiative Tracking ID) and a description of the Target for each applicable year (2023 Target & Unit, 2024 Target & Unit, 2025 Target & Unit), the "% Risk Impact" for each respective year, and the method of verification. As noted in Section 7.2.1, the % Risk Impact and method of verification columns are not a part of the Target. Instead, the controlling target information is in the "Target & Unit" columns for each respective year.
- Table 8-15 Information Summary: Table 8-15 contains the Q2 and Q3 quarterly targets for 2023 and 2024 as well as the year end targets for 2023, 2024, and 2025 for inspections. Please note, the end of year targets in Table 8-15 are also represented in Table 8-14. For readability and efficiency, the annual targets in Table 8-14 include additional language to provide more context on the quantitative target values as well as all other required information associated with targets (i.e., method of verification, % risk Impact). Therefore, if additional context is needed to better understand the quarterly target values in Table 8-15, please refer to the 2023 Target & Unit, 2024 Target & Unit, 2025 Target & Unit columns in Table 8-14 that have the same associated target name (Target Name).

- Reporting: Unless changed through Energy Safety's Change Order process, PG&E will use the Targets in Table 8-14 and Table 8-15 below for quarterly compliance reporting including the Quarterly Data Report (QDR), Quarterly Notification (QN), and the Annual Report on Compliance (ARC). It is also important to note that throughout this 2023-2025 WMP, we discuss current plans for wildfire-related activities in addition to the Targets in Table 8-14 and Table 8-15. The timing and scope of these additional activities and work may change. We will not be reporting on these plans or activities in our QDR, QN, or ARC because they are not Targets but are descriptions of plans and activities in our 2023-2025 WMP to provide a complete picture of our mitigation activities.

- % Risk Impact: The % Risk Impact provided in Table 8-14 is calculated based on the risk reduction of the mitigation initiative divided by total overall utility risk as defined in Section 6.4.2, Section 7.2.2.2, and Section 7.2.2.3. The % Risk Impact provided is an estimate based on the best available workplans applied against the latest risk models as of time of this filing. Please note, 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, for inspection and line sensor related targets, since inspections in of themselves do not reduce risk, instead we provided an "Eyes-on-Risk" value to provide insights into the level of risk being assessed.

- External Factors: All targets in the below Table 8-14 and Table 8-15 are subject to External Factors which represent reasonable circumstances which may impact execution against targets including, but not limited to, physical conditions, landholder refusals, environmental delays, 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.

- HFTD, HFRA, Buffer Areas: Unless stated otherwise, all initiative work described in Table 8-14 involves work or audits on units or equipment located in, traversing, energizing, or protecting units or equipment in HFTD, HFRA, or Buffer Zone areas.

- Utility Initiative Tracking ID: We are including Initiative Tracking IDs in each section that has associated targets and objectives. Table 8-14 and Table 8-15 display the Tracking IDs we are implementing to tie the targets to the narratives and initiatives in the WMP. The Initiative Tracking IDs will also be used for reporting in the QDR.

TABLE 8-14:
PG&E'S VM TARGETS

Target Name	Initiative Activity Tracking ID	Reference Section	2023 Target & Unit	x% Risk Impact 2023	2024 Target & Unit	x% Risk Impact 2024	2025 Target & Unit	x% Risk Impact 2025	Method of Verification
LiDAR Data Collection – Transmission[(a)]	VM-01	8.2.2.1.1	Collect LiDAR data of the Transmission System (17,500 circuit miles). The Transmission System circuit miles include both HFTD/HFRA and non-HFTD Transmission circuit miles.	N/A	Collect LiDAR data of the Transmission System (17,500 circuit miles). The Transmission System circuit miles include both HFTD / HFRA and non-HFTD Transmission circuit miles.	N/A	Collect LiDAR data of the Transmission System (17,500 circuit miles). The Transmission System circuit miles include both HFTD / HFRA and non-HFTD Transmission circuit miles.	N/A	LiDAR Contractor Work Complete Attestation
Pole Clearing Program	VM-02	8.2.3.1	Inspect, clear, and maintain, where clearing is necessary 77,503 poles per Vegetation Control Standard TD-7112S.	<1%	2024 pole count to be adjusted by the ending pole population in the previous year (2023) poles per Vegetation Control Standard TD-7112S will be inspected, cleared, and maintained where clearing is necessary.	<1%	2025 pole count to be adjusted by the ending pole population in the previous year (2024) poles per Vegetation Control Standard TD-7112S will be inspected, cleared, and maintained where clearing is necessary.	<1%	List of all poles in VM database as of October 1, 2022, with work status

TABLE 8-14:
PG&E'S VM TARGETS
(CONTINUED)

Target Name	Initiative Activity Tracking ID	Reference Section	2023 Target & Unit	x% Risk Impact 2023	2024 Target & Unit	x% Risk Impact 2024	2025 Target & Unit	x% Risk Impact 2025	Method of Verification
Tree Removal	VM-04	8.2.2.2.4	Removal of 15,000 trees identified from the legacy EVM program.	<1%	Removal of 20,000 trees identified from the legacy EVM program.	<1%	Removal of 25,000 trees identified from the legacy EVM program.	<1%	Report from VM database reflecting completed work.
Defensible Space Inspections – Distribution Substation[(b)]	VM-05	8.2.2.3.1	Complete defensible space inspections in alignment with the guidelines set forth in LAND 4001P-01 at 131 distribution substations. Co-located Hydroelectric substations and Transmission & Distribution substations are counted separately as two distinct units.	53% (Eyes-on-Risk)	Complete defensible space inspections in alignment with the guidelines set forth in LAND 4001P-01 at 131 distribution substations. Co-located Hydroelectric substations and Transmission & Distribution substations are counted separately as two distinct units.	53% (Eyes-on-Risk)	Complete defensible space inspections in alignment with the guidelines set forth in LAND 4001P-01 at 131 distribution substations. Co-located Hydroelectric substations and Transmission & Distribution substations are counted separately as two distinct units.	53% (Eyes-on-Risk)	Closed notifications

TABLE 8-14:
PG&E'S VM TARGETS
(CONTINUED)

Target Name	Initiative Activity Tracking ID	Reference Section	2023 Target & Unit	x% Risk Impact 2023	2024 Target & Unit	x% Risk Impact 2024	2025 Target & Unit	x% Risk Impact 2025	Method of Verification
Defensible Space Inspections – Transmission Substation[(b)]	VM-06	8.2.2.3.1	Complete defensible space inspections in alignment with the guidelines set forth in LAND 4001P-01 at 55 transmission substations. Co-located Hydroelectric substations and Transmission & Distribution substations are counted separately as two distinct units.	22% (Eyes-on-Risk)	Complete defensible space inspections in alignment with the guidelines set forth in LAND 4001P-01 at 55 transmission substations. Co-located Hydroelectric substations and Transmission & Distribution substations are counted separately as two distinct units.	22% (Eyes-on-Risk)	Complete defensible space inspections in alignment with the guidelines set forth in LAND 4001P-01 at 55 transmission substations. Co-located Hydroelectric substations and Transmission & Distribution substations are counted separately as two distinct units.	22% (Eyes-on-Risk)	Closed notifications

TABLE 8-14:
PG&E'S VM TARGETS
(CONTINUED)

Target Name	Initiative Activity Tracking ID	Reference Section	2023 Target & Unit	x% Risk Impact 2023	2024 Target & Unit	x% Risk Impact 2024	2025 Target & Unit	x% Risk Impact 2025	Method of Verification
Defensible Space Inspections – Hydroelectric Substations and Powerhouses	VM-07	8.2.2.3.1	Complete defensible space inspections in alignment with the guidelines set forth in LAND 5201P-01 at 61 Hydroelectric Generation Substations and Powerhouses. Co-located Hydroelectric substations and Transmission & Distribution substations are counted separately as two distinct units.	25% (Eyes-on-Risk)	Complete defensible space inspections in alignment with the guidelines set forth in LAND 5201P-01 at 61 Hydroelectric Generation Substations and Powerhouses. Co-located Hydroelectric substations and Transmission & Distribution substations are counted separately as two distinct units.	25% (Eyes-on-Risk)	Complete defensible space inspections in alignment with the guidelines set forth in LAND 5201P-01 at 61 Hydroelectric Generation Substations and Powerhouses. Co-located Hydroelectric substations and Transmission & Distribution substations are counted separately as two distinct units.	25% (Eyes-on-Risk)	Closed notifications

TABLE 8-14:
PG&E'S VM TARGETS
(CONTINUED)

Target Name	Initiative Activity Tracking ID	Reference Section	2023 Target & Unit	x% Risk Impact 2023	2024 Target & Unit	x% Risk Impact 2024	2025 Target & Unit	x% Risk Impact 2025	Method of Verification
Vegetation Management – Quality Verification	VM-08	8.2.5	Each of the 3 programs (Routine Distribution, Routine Transmission and Pole Clearing) must achieve an 95% quality verification audit results pass rate. The number of samples for Quality Verification audits for the 3 programs (Routine Distribution, Routine Transmission and Pole Clearing) are based on quality control completed work in HFTD areas. Quality verification audit locations will be identified using a statistically valid approach with a 95% confidence level (CL) and 5% margin of error. The pass rate and associated number of quality verification audit locations are based on the actual work completed in the calendar year.	N/A	The scope for Quality Verification reviews is subject to change and will be decided based on learning's from prior years, aligned to business needs and risks.	N/A	The scope for Quality Verification reviews is subject to change and will be decided based on learning's from prior years, aligned to business needs and risks.	N/A	QV VM final reports

(a) VM-01 LiDAR is flown in late summer and early fall in the prior year to enable ground inspection's next cycle to begin in November that then allows tree work to commence on January 1 of the following year.

(b) VM-05 and VM-06 Defensible Space inspections begin in late November to enable work mitigation to be completed before fire season begins in the following year.

TABLE 8-15
VEGETATION INSPECTIONS TARGETS BY YEAR

Target Name	Initiative Activity Tracking ID	Reference Section	Target End of Q2 2023 & Unit	Target End of Q3 2023 & Unit	End of Year Target 2023 & Unit	Target End of Q2 2024 & Unit	Target End of Q3 2024 & Unit	End of Year Target 2024 & Unit	End of Year Target 2025 & Unit
LiDAR Data Collection – Transmission[a]	VM-01	8.2.2.1.1	17,500 Circuit Miles	17,500 Circuit Miles	17,500 Circuit Miles	17,500 Circuit Miles	17,500 Circuit Miles	17,500 Circuit Miles	17,500 Circuit Miles
Pole Clearing Program	VM-02	8.2.3.1	57,750 Distribution poles	77,503 Distribution poles	77,503 Distribution poles	47,250 Distribution poles	63,000 Distribution poles	63,000 Distribution poles	52,000 Distribution poles
Defensible Space Inspections – Distribution Substation[b]	VM-05	8.2.2.3.1	130 Distribution Substations	131 Distribution Substations	131 Distribution Substations	130 Distribution Substations	131 Distribution Substations	131 Distribution Substations	131 Distribution Substations
Defensible Space Inspections – Transmission Substation[b]	VM-06	8.2.2.3.1	55 Transmission Substations	55 Transmission Substations	55 Transmission Substations	55 Transmission Substations	55 Transmission Substations	55 Transmission Substations	55 Transmission Substations
Defensible Space Inspections – Hydroelectric Substations and Powerhouses	VM-07	8.2.2.3.1	61 Hydroelectric Substations and Powerhouses	61 Hydroelectric Substations and Powerhouses	61 Hydroelectric Substations and Powerhouses	61 Hydroelectric Substations and Powerhouses	61 Hydroelectric Substations and Powerhouses	61 Hydroelectric Substations and Powerhouses	61 Hydroelectric Substations and Powerhouses

(a) VM-01 LiDAR is flown in late summer and early fall in the prior year to enable ground inspection's next cycle to begin in November that then allows tree work to commence on January 1 of the following year.

(b) VM-05 and VM-06 Defensible Space inspections begin in late November to enable work mitigation to be completed before fire season begins in the following year.

8.2.1.3 Performance Metrics

Performance metrics indicate the extent to which an electrical corporation's WMP is driving performance outcomes. The electrical corporation must:

- *List the performance metrics the electrical corporation uses to evaluate the effectiveness of its VM and inspections in reducing wildfire and Public Safety Power Shutoff (PSPS) risk.*[136]

For each of these performance metrics listed, the electrical corporation must:

- *Report electrical corporation's performance since 2020 (if previously collected);*
- *Project performance for 2023-2025; and*
- *List method of verification.*

The electrical corporation must ensure that each metric's name and values are the same in its WMP reporting as its QDR reporting (specifically, QDR Table 2 and QDR Table 3). Metrics listed in this section that are the same as performance metrics required by Energy Safety and reported in QDR Table 2 (Performance Metrics) must match those reported in QDR Table 2. Metrics listed in this section that are not the same as any of the performance metrics identified by Energy Safety and reported in QDR Table 2 must match those reported in QDR Table 3.

The electrical corporation must:

- *Summarize its self-identified performance metric(s) in tabular form; and*
- *Provide a brief narrative that explains trends in the metrics.*

Table 8-16 provide are examples of the minimum acceptable level of information. The electrical corporation must provide a brief narrative that explains its trends.

The number of Risk events includes ignitions, wire downs, and outages in HFTD Tier 2 and Tier 3. The metric includes risk events on high wind warning days, red flag warning days, and no wind event days. The Number of Risk events is weather dependent. The projected number of Risk Events is based on a 5-year average that allows us to better account for yearly fluctuations.

The time between vegetation inspection findings and resultant trimming activities in the HFTD for Transmission and Distribution is based on the average median number of hours between inspection and remediation. Projections are based on the median average to account for the annual variation in the recorded data. We anticipate the

[136] There may be overlap between the performance metrics the electrical corporation uses and performance metrics required by Energy Safety. The electrical corporation must list these overlapping metrics in this section in addition to any unique performance metrics it uses.

updated processes and standards will reduce the average time between inspection and remediation.

The number of open VM work orders represents the total number of trees. Projections are based on planned updates to standards and procedures that will enable us to reduce the open VM work orders.

The number of past due open VM work orders represents the total number of trees and includes Priority 2 trees and Second Patrol (Tree Mortality) trees excluding constrained trees. There were no Priority 1 past due open work orders at the time the data was generated (February 28, 2023). Projections are based on the average of 2020-2022 and include a reduction of 5 percent each year.

TABLE 8-16:
VM AND INSPECTION PERFORMANCE METRICS RESULTS BY YEAR

Performance Metrics	2020	2021	2022	2023 Projected	2024 Projected	2025 Projected	Method of Verification (i.e., third-party evaluation, QDR)
Number of risk events (ignitions, wire downs, and outages in HFTD)	9,744	12,022	6,660	10,034	10,034	10,034	QDR[a]
Time between vegetation inspection finding and resulting trimming activities (in HFTD) – Transmission	2,221	2,080	2,823	2,700	2,600	2,500	QDR[b]
Time between vegetation inspection finding and resulting trimming activities (in HFTD) – Distribution	1,819	1,030	1,710	1,700	1,600	1,500	QDRI[c]
Number of VM open work orders	34	2,903	309,582	<275,000	<275,000	<275,000	QDR[d]
Number of VM open work orders – past due	204	11	114	110	105	100	QDR[e]

(a) QDR Table 2, QDR No. 1a – sum of HFTD Tier 2 and HFTD Tier 3.
(b) QDR Table 2, QDR No. 2t – annual average (recorded) and Transmission (projected) for HFTD Tier 2 and Tier 3.
(c) QDR Table 2, QDR No. 2d – annual average (recorded) and Distribution (projected) for HFTD Tier 2 and Tier 3.
(d) QDR Table 2, QDR No. 6a.
(e) QDR Table 2, QDR No. 6b.

8.2.2 Vegetation Management Inspections

In this section, the electric corporation must provide an overview of its procedures for VM inspections.

The electrical corporation must first summarize details regarding its VM inspections in Table 8-17*. The table must include the following:*

- *Type of Inspection: Distribution, transmission, or substation, etc.;*
- *Inspection Program Name: Identify various inspection programs within the electrical corporation (e.g., routine, enhanced vegetation, high-risk species, and off-cycle);*
- *Frequency or Trigger: Identify the frequency or triggers, such as inputs from the risk model. Includes differences in frequency or trigger by HTFD Tier;*
- *Method of Inspection: Identify the methods used to perform the inspection (e.g., patrol, detailed, sounding or root examination, aerial, and LiDAR); and*
- *Governing Standards and Operating Procedures: Identify the regulatory requirements and the electrical corporation's PG&E's procedures for addressing them.*
- *The electrical corporation must then provide a narrative overview of each vegetation inspection program identified in the table above. Section 8.2.2.1 provides instructions for the overviews. The sections should be numbered 8.2.2.1 to Section 8.2.2.n (i.e., each vegetation inspection program is detailed in its own section.) The electrical corporation must include inspection programs it is discontinuing or has discontinued since the last WMP submission. In these cases, the electrical corporation must explain why the program is being discontinued or has been discontinued.*

Utility Initiative Tracking IDs: VM-10

TABLE 8-17:
VM INSPECTION FREQUENCY, METHOD, AND CRITERIA

Type(1),(2)	Inspection Program Name	Frequency or Trigger	Method of Inspection	Governing Standards and Operating Procedures
Transmission	Routine	Recurring Annual Cycle	LiDAR with follow up ground patrol	NERC Standard Federal Agency Code (FAC)-003-04 NERC GO 95 Rule 35 PRC 4292 PRC 4293 Transmission Non-Orchard Routine Patrol Procedure (TD-7103P-01) Transmission Orchard Routine Patrol Procedure (TD-7103P-02) Transmission Vegetation Management Standard (TD-7103S)
Transmission	Second Patrol	Recurring Cycle	LiDAR with follow up ground patrol	NERC Standard FAC-003-04 GO 95 Rule 35 PRC 4292 PRC 4293 ESRB-4 Transmission Non-Orchard Routine Patrol Procedure (TD-7103P-01)
Transmission	Integrated Vegetation Management	Prioritization is based on aging work cycles and evaluation of vegetation re-growth	LiDAR with follow up ground patrol	Transmission Integrated Vegetation Management (TIVM) Procedure (TD-7103P-04).
Distribution	Routine	Recurring Annual Cycle	Ground Based Patrol	GO 95 Rule 35 and Rule 18 PRC 4292 PRC 4293 Distribution Routine Patrol Procedure (DRPP) (TD-7102P-01) Distribution Vegetation Management Standard (TD-7102S)

TABLE 8-17:
VM INSPECTION FREQUENCY, METHOD, AND CRITERIA
(CONTINUED)

Type[(1),(2)]	Inspection Program Name	Frequency or Trigger	Method of Inspection	Governing Standards and Operating Procedures
Distribution	Second Patrol	Approximately 6 months offset from Routine Patrol	Ground Based Patrol	GO 95 Rule 35 and Rule 18 PRC 4292 PRC 4293 ESRB-4 DRPP (TD-7102P-01) Vegetation Management Second Patrol Procedure (TD-7102P-23)
Distribution	VM for Operational Mitigations	Workplan to Reduce Customer Impacts due to Vegetation Outages on EPSS - If at any point PG&E determines this program does not effectively support efforts to reduce customer impacts due to Vegetation Outages on EPSS when compared to other viable approaches, PG&E will pause or discontinue the VMOM efforts.	Ground Based Patrol	GO 95 Rule 35 PRC 4293
Distribution	Tree Removal Inventory	Workplan to Remove or Re-Evaluate Trees previously identified by EVM - If at any point PG&E determines this program does not effectively support efforts to remove or re-evaluate trees identified to EVM when compared to other viable approaches, PG&E will pause or discontinue the TRI efforts.	Ground Based Patrol	GO 95 Rule 35 PRC 4293 PUC 8386
Distribution	Focused Tree Inspections	Q2 2023 – Pilot	Ground Based Patrol	GO 95 Rule 35 PRC 4293

TABLE 8-17:
VM INSPECTION FREQUENCY, METHOD, AND CRITERIA
(CONTINUED)

Type[(1),(2)]	Inspection Program Name	Frequency or Trigger	Method of Inspection	Governing Standards and Operating Procedures
Substation	Defensible Space Inspection	Annually	Ground Inspection of substation	TD-3328S, LAND-4001P-01, LAND-5201P-01 Rule 18

Note 1

- Transmission: Detailed planning for the Routine Line Clearance Program is done in the fourth quarter of each year for the following year. The detailed planning process includes forecasting the number of units to be worked on each transmission line and setting the following years' schedule; and
- Distribution: Detailed planning is conducted in the third and fourth quarter of each year for the following year. The detailed planning process includes forecasting the number of units that will be worked on each distribution circuit or project and setting the following years' schedule.

Note 2

- Transmission: Transmission programs include Routine NERC and Routine Non-NERC. These programs recur annually, with the IVM Program recurring based on vegetation growth response. See Section 8.2.2.1. See Table 8-17 for mode of inspection; and
- Distribution: Distribution programs include Routine patrols which occur annually, and Second Patrol which occurs with an approximate six-month offset from Routine patrols. See Section 8.2.2.2. See Table 8-17 for mode of inspection.
- Substation: PG&E assesses the area around ET and Distribution Substations (including power houses and switching stations) in HFTD and HFRA areas to identify potential flammable fuels and vegetation for removal, minimizing the potential for ignition spread outside of facilities and providing improved structure defense capability for firefighting purposes. See Section 8.2.2.3. See Table 8-17 for mode of inspection.

8.2.2.1 Vegetation Inspection – Transmission

Process

In this section, the electrical corporation must provide an overview of the individual vegetation inspection program, including inspection criteria and the various inspection methods used for each inspection program.

Include relevant visuals and graphics depicting the workflow and decision-making process the electrical corporation uses for the inspection program.

Frequency or Triggers

In this section, the electrical corporation must identify the frequency or triggers used in the inspection program, such as inputs from the risk model. It must also identify how the frequency or trigger might differ by HFTD Tier or other risk designation.

If the inspection program is based on a schedule, 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.

Accomplishments, Roadblocks, and Updates

In this section, the electrical corporation must discuss:

- *Noteworthy accomplishments for the inspection program since the last WMP submission;*
- *Roadblocks the electrical corporation has encountered while implementing the inspection program and how the electrical corporation has addressed the roadblocks; and*
- *Changes/updates to the inspection program since the last WMP submission including known future plans (beyond the current year) and new/novel strategies the electrical.*

Trees or other vegetation that make contact or cross within flash-over distance of high voltage transmission lines can cause phase-to-phase or phase-to-ground electrical arcing, fire ignition, or local, regional, or cascading, grid-level service interruption. Dense vegetation growing within the right-of-way (ROW) can act as a fuel bed for wildfire ignition. Vegetation growing close to any pole or structure can impede inspection of the structure base and in some cases can damage the structure.

PG&E’s Transmission VM Program consists of several different methods for inspecting vegetation in proximity to transmission lines. The programs described below help us safely and reliably operate transmission lines while complying with state laws and regulations.

Compliance With Legal and Regulatory Requirements

The Transmission VM Program is designed to comply with state and federal laws and regulations including: (1) GO 95 Rule 35; (2) PRC Section 4292; (3) PRC Section 4293; and (4) NERC Standard FAC-003-04.

1) GO 95 Rule 35: Requires a year-round clearance to power lines of a minimum 18 inches (18”) up to 150 kilovolts (kV), 22.5” for 150kv-300kV, and 75” above 300 kV. Fire safety regulations require a minimum clearance of 4 feet (ft.) year-round for high-voltage power lines for lines up to 300 kV and 10 ft. clearance for 300 kV and above in the CPUC-designated HFTD areas. Rule 35 also requires the removal of dead, diseased, defective, and dying trees that could fall into the lines.

2) PRC 4292: Administered by California Department of Forestry and Fire Protection (CAL FIRE), it requires that PG&E maintain a firebreak of at least 10 ft. in radius around a utility pole, with tree limbs within the 10-ft. radius of the pole being removed up to 8 ft. above ground. From 8-ft. to conductor height requires removal of dead, diseased or dying limbs and foliage. This applies in the and State Responsibility Areas (SRA) during the designated fire season. These clearances apply to non-exempt equipment at Distribution and Transmission voltages.

3) PRC 4293: Administered by CAL FIRE, it requires that PG&E maintain a 4-foot minimum clearance for power lines between 2,400 and 72,000 volts (V), and 10-foot clearance for conductors 115,000 V and above. PRC 4293 states that dead trees, old or rotten trees, trees weakened by decay or disease, and trees or portions thereof that are leaning toward the line which may contact the line from the side or may fall on the line shall be felled, cut, or trimmed to remove such hazard. This applies to the SRA during the designated fire season.

4) NERC Standard FAC-003-04: Requires maintaining a reliable ET system by using a defense-in-depth strategy to manage vegetation located on transmission ROWs and minimize encroachments from vegetation located adjacent to the ROW, thus preventing the risk of those vegetation related outages that could lead to cascading outages.

PG&E’s transmission VM Program also complies with PG&E’s internal Transmission Non-Orchard Routine Patrol Procedure (TD-7103P-01) and Transmission Orchard Routine Patrol Procedure (TD-7103P-02) which provide instruction and requirements for annual routine inspection of vegetation around PG&E Electric Transmission Lines (ETL) to ensure the safe and reliable operation of facilities. This procedure also provides guidance for PG&E employees and contractors for meeting or exceeding the requirements of NERC Standards for Vegetation Management, NERC FAC-003-4 Transmission Vegetation Management.

PG&E operates our lines in ET ROWs that are home to vegetation ranging from sparse to extremely dense. Our transmission lines also pass through urban, agricultural, and forested settings. The corridor environment is dynamic and requires ongoing management to ensure vegetation stays clear of energized conductors and other equipment. Vegetation inspection is a required operational step in an overall VM Program. Accordingly, PG&E has developed an annual inspection cycle program as part of our overall Transmission VM Program to respond to the diverse and dynamic environment of our service territory. The Routine NERC and Routine Non-NERC Programs are annually recurring. The IVM Program recurs every three to five years. The frequency and prioritization for each of these programs is described below.

Over time we will evaluate emerging technologies to enhance focus of and streamline the execution of vegetation management inspections

8.2.2.1.1 Routine Transmission NERC and Non-NERC

Utility Initiative Tracking IDs: VM-01

Process

The Routine NERC Program includes LiDAR inspection, visual verification of findings, and mitigation of vegetation encroachments on approximately 6,800 miles of NERC Critical lines. One hundred percent of inspection and work plan completion are required by NERC Standard FAC-003-4. Work is prioritized based on aerial LiDAR detection. This program recurs annually.

The Routine Non-NERC Program includes LiDAR inspection, visual verification of findings, and mitigation of vegetation encroachments, as well as other vegetation conditions on approximately 11,400 miles of transmission lines not designated as critical by NERC. Work is prioritized based on aerial LiDAR detection. This program recurs annually.

The Transmission Routine NERC and Non-NERC Inspection cycle consists of a LiDAR inspection followed by a ground patrol based on LiDAR findings. The LiDAR inspection provides an inventory of potential vegetation risk and the results of the ground patrol prescribe the forecasted tree work to comply with state and federal regulations. Having two resources (LiDAR and ground patrol) support the inspection cycle increases the quality of the vegetation risk mitigation.

Urgent work is prioritized. LiDAR detects potential urgent follow up ground patrol and the follow up ground patrol prescribes urgent tree work when conditions so dictate.

Frequency or Triggers

The Routine NERC and Routine Non-NERC Programs are annually recurring. Routine NERC inspections are prioritized each year so that 100 percent of tree work can be completed by December 31.

The inspection of Routine Non-NERC projects located in HFTD/HFRA areas are prioritized in the schedule each year in preparation for wildfire season.

Routine VM Transmission manages the time between last inspection cycle and time between last trim cycle for both compliance and wildfire risk mitigation. Each year we verify overhead transmission assets to ensure that the current system line miles and

ETL are included in the VM planning and execution of the work. This ensures that we are patrolling 100 percent of the system each year.[137,138]

We prioritize ETL that have Enhanced Powerline Safety Settings (EPSS) and lines sections in the HFTD and HFRA.

Accomplishments

- Developed a Conductor Blowout Targeted Plan focused on where conductor can blow outside ROW into the trees;
- Developed Outage and Ignition Dashboards that provide a daily view into VM-related issues; and
- Developing the Tree Growth Model.

Roadblocks

PG&E can be constrained by environmental delays, individual customer issues, permitting delays/restrictions or operational holds, weather conditions, active wildfire, and accessibility of the area where transmission system inspections have been identified. If the constrained work is compliance related, we work through our VM processes to resolve the roadblock and execute the work. This would include everything from securing a permit to rescheduling work timing due to field conditions.

Updates

In addition to the changes and updates listed in the accomplishments section above, PG&E has an ongoing Transmission ROW Expansion program that is focused on reliability and was initiated in 2017. That program will continue in 2023 but is not directly related to wildfire mitigation. However, to the extent ROWs are being expanded, there will be incremental wildfire mitigation benefits resulting from decreased vegetation around PG&E’s transmission lines.

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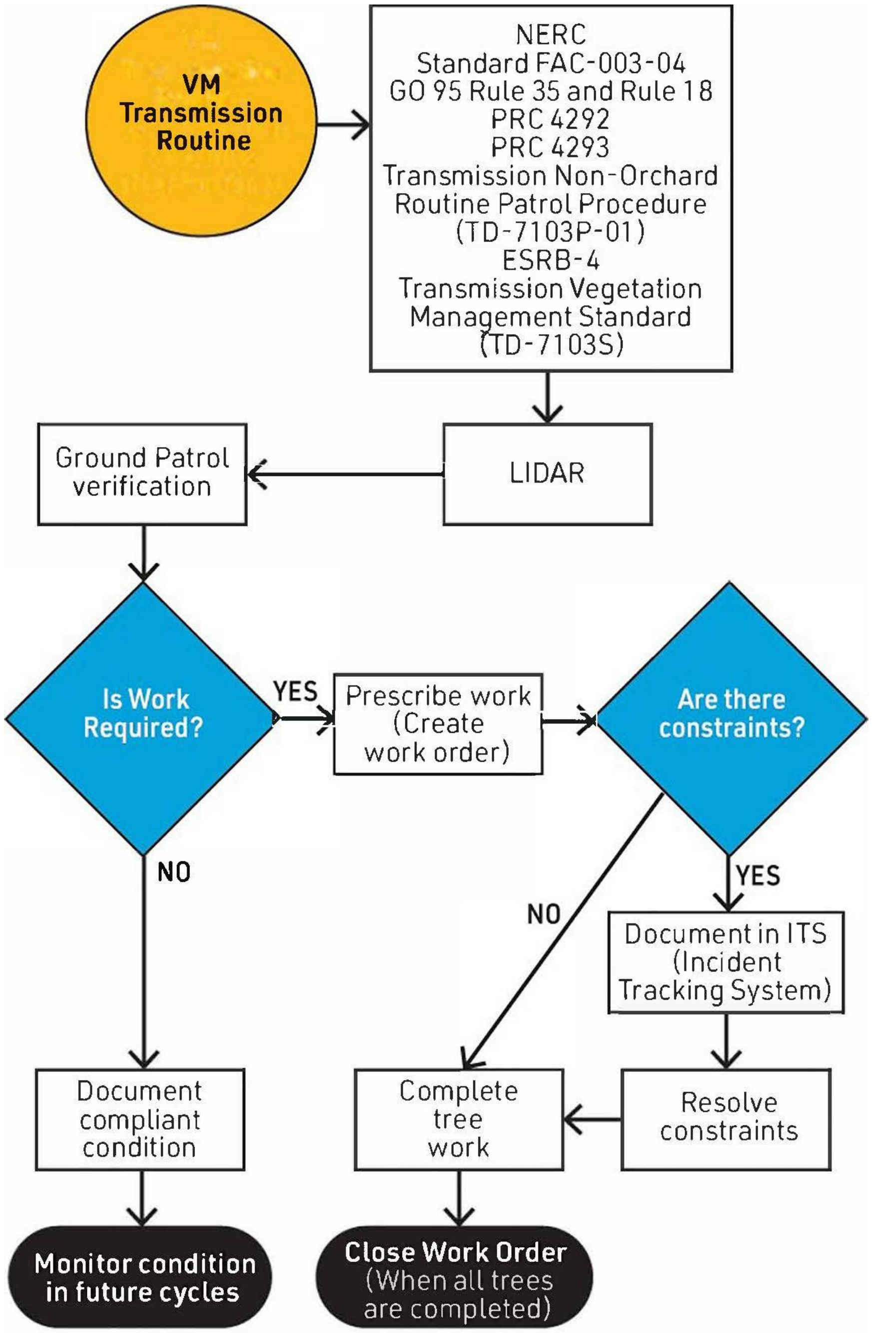
[137] In addition to ignition risk there is also compliance risk related to federal regulation FAC 003-4 that we consider when planning and executing NERC work (inspections and associated tree work). For example, requirement seven states that tree work associated with NERC transmission lines (230 kV, 500 kV and another sub 230 kV corridor) must be completed by December 31. Therefore, we frontload NERC inspections and NERC tree work in the cycle so that we have ample time to complete the tree work given known constraints.

[138] Removal and tree felling is the preferred method for Routine NERC and Non-NERC work and agency and environmental permitting are often required. Since these permits can take months to acquire, we frontload NERC inspections on January 1 so that we can meet the December 31 target for completing the tree work.

Figure PG&E-8.2.2-1 below depicts PG&E's VM Transmission Inspection process.

FIGURE PG&E-8.2.2-1:
PG&E'S VM TRANSMISSION INSPECTION PROCESS



8.2.2.1.2 Transmission Second Patrol

Process

PG&E conducts a Second Patrol aerial LiDAR inspection in the HFTD areas of our system at the height of the vegetation growing season which coincides with the beginning of historically the most active part of the California fire season. This patrol allows PG&E to conduct a supplemental assessment of potential tree growth following seasonal rain through high fire threat areas to reduce the potential of ignitions.

Frequency or Triggers

As described in Section 8.2.2.1.1, “Process.”

Accomplishments

See Section 8.2.2.1.1

Roadblocks

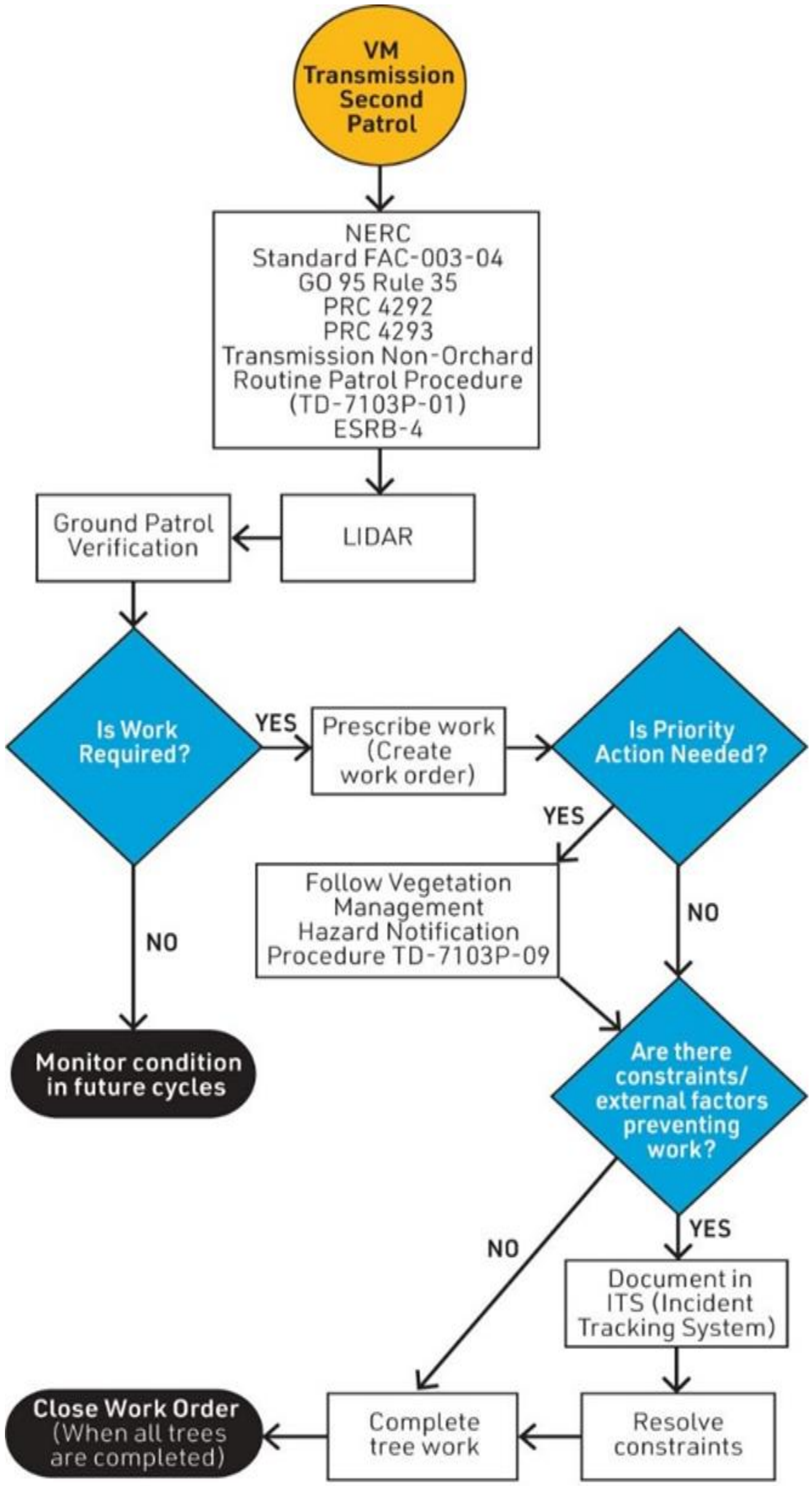
See Section 8.2.2.1.1

Updates

There are no updates to our Transmission Second Patrol program.

Figure PG&E-8.2.2-2 below depicts PG&E's VM Transmission Second Patrol process.

FIGURE PG&E-8.2.2-2:
PG&E'S VM TRANSMISSION SECOND PATROL PROCESS



8.2.2.1.3 Integrated Vegetation Management (IVM)

Process

The IVM Program is an ongoing maintenance program designed to maintain cleared ROWs in a sustainable and compatible condition by eliminating tall-growing vegetation and promoting low-growing, compatible vegetation. Prioritization is based on aging work cycles and evaluation of vegetation re-growth. After the initial work is performed, the ROWs are reassessed every 2-5 years. The IVM Program follows TIVM, TD-7103P-04.

Frequency or Triggers

Prioritization is based on aging work cycles and evaluation of vegetation re-growth. After the initial work is performed, the ROWs are reassessed every 2-5 years.

Accomplishments

See Section 8.2.2.1.1

Roadblocks

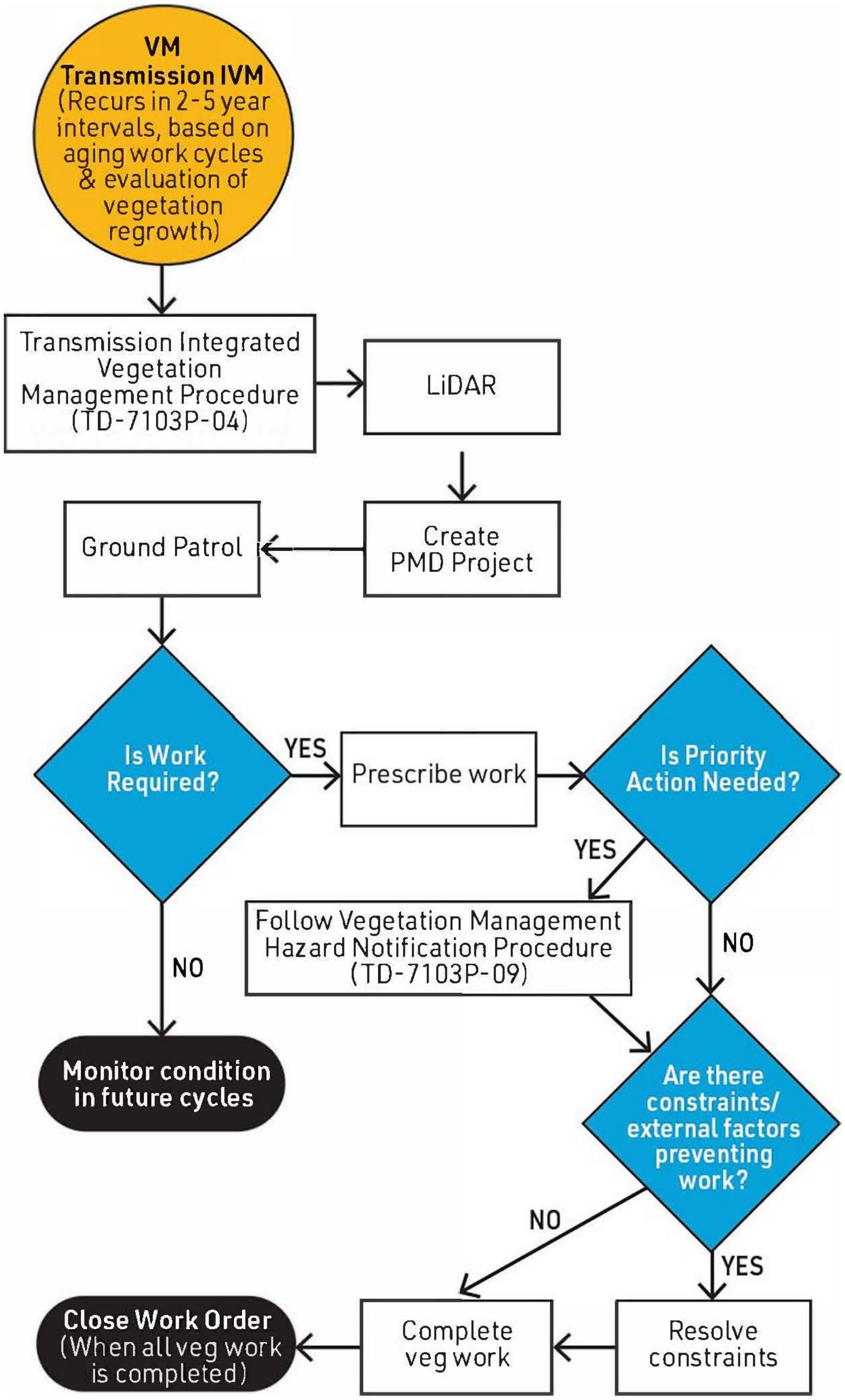
See Section 8.2.2.1.1

Updates

There are no updates to our Transmission Second Patrol program.

Figure PG&E-8.2.2-3 below depicts PG&E's IVM process.

FIGURE PG&E-8.2.2-3:
PG&E'S IVM PROCESS



8.2.2.2 Vegetation Inspections – Distribution

Vegetation located close to electrical equipment can cause a fire by contacting the equipment, and either catching fire or dropping a spark that could cause other vegetation to ignite. Vegetation trimming and hazard tree removal reduces the potential for vegetation and wire conflict. PG&E's VM distribution program inspects approximately 80,000 miles of overhead distribution electric facilities on a recurring cycle. PG&E's distribution VM Program includes different types of patrols designed to comply with state and federal laws and regulations: (1) GO 95, Rule 35; (2) California PRC Section 4293.

1) GO 95 Rule 35: Requires year-round clearance for power lines of a minimum 18 inches. Fire safety regulations require a minimum clearance of 4 ft. year-round for high-voltage power lines in the CPUC-designated HFTD areas. Rule 35 also requires the removal of known dead, diseased, defective, and dying trees that could fall into the lines.

2) PRC 4293: Administered by CAL FIRE. It requires that PG&E maintain a 4 ft minimum clearance for power lines between 2,400 V and 72,000 V, and a 10 ft clearance for conductors 115,000 V and above. PRC 4293 states that dead, old, or rotten trees, trees weakened by decay or disease, and trees or portions thereof that are leaning toward the line which may contact the line from the side or may fall on the line shall be felled, cut, or trimmed so as to remove such hazard. This applies to the SRA during the designated fire season.

PG&E's distribution VM Program also complies with PG&E's internal DRPP (TD-7102P-01) which details requirements and expectations for inspection and completion of the work to ensure compliance with applicable laws and regulations, as well as conformance to internal Best Management Practices (BMP).

Through the distribution inspection program PG&E identifies maintenance issues that are completed consistent with regulatory requirements:

- Dead, dying and declining trees, or dead portions of trees that may contact PG&E facilities if they fail;
- Green trees observed within the Minimum Distance Requirement (MDR) or with the potential to encroach within the MDR before the next tree work cycle;
- Trees causing strain or abrasion on secondary lines; and
- Abnormal field conditions.

VM inspects vegetation throughout its distribution system on a recurring cycle to identify maintenance issues.

Over time we will evaluate emerging technologies to enhance focus of and streamline the execution of vegetation management inspections.

8.2.2.2.1 Distribution Routine Patrol

Process

The VM routine program performs scheduled inspections on all overhead primary and secondary distribution facilities to maintain radial clearance between vegetation and conductors by identifying trees that will encroach within the MDR in accordance with regulatory requirements and/or PG&E procedures. In addition, dead, dying, and declining trees that may fail and strike conductors are identified and mitigated.

Frequency or Triggers

PG&E's VM distribution program inspects approximately 80,000 miles of overhead distribution electric facilities on a recurring annual cycle.

Accomplishments

- Transitioned from the Enhanced Vegetation Management (EVM) Program to three new programs to more effectively manage vegetation risk;
- Adjusted the scope of the Utility Defensible Space (UDS) Program based on feedback and benchmarking with Southern California Edison and San Diego Gas & Electric Company;
- Developed Outage and Ignition Dashboards that provide a daily view into VM-related issues;
- Developing the Tree Growth Model;
- Developed AOCs in response to 2022 WMP Revision Notice 22-09; and
- Received business case approval for updated digitized Incident Investigations.

Roadblocks

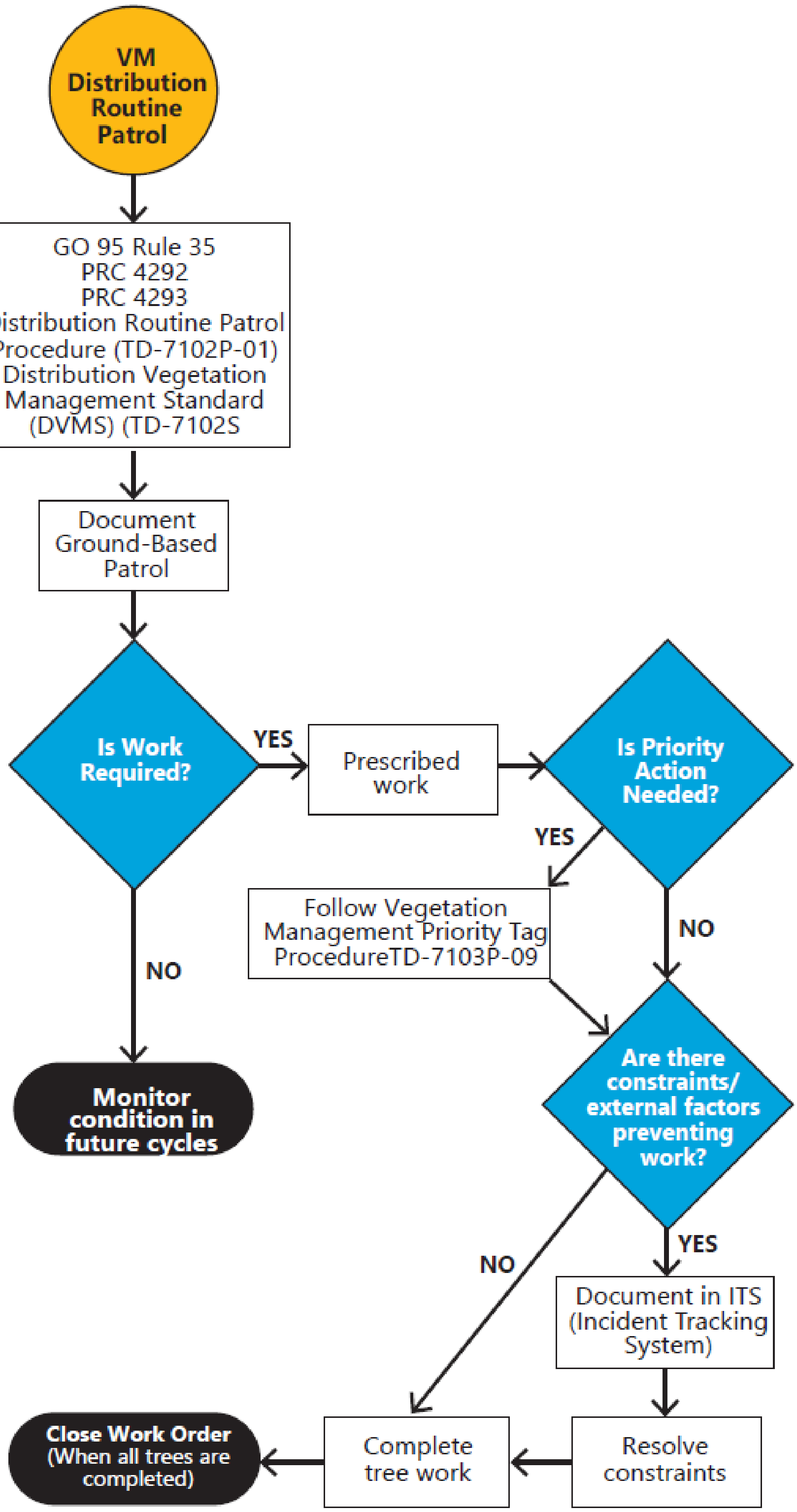
Operational considerations such as access issues due to snow or mud, agricultural production cycles, and seasonal environmental concerns can create limited operating periods in some areas that make them only workable for portions of the year, which by necessity dictate some of the VM prioritization and scheduling of work. Since we inspect and maintain our entire distribution system annually, it is operational and execution considerations—as opposed to considerations based on risk—that dictate when certain areas are inspected and maintained.

Updates

PG&E is transitioning the maintenance of EVM clearances that have been achieved to Routine VM patrols. We established routine maintenance requirements for electric distribution circuits where EVM scope clearances have been performed (in HFTD designated areas) and passed by work verification. The requirements have been documented in Utility Bulletin EVM Transition to Distribution Routine Patrol (TD-7102P-01-B026).

Figure PG&E-8.2.2-4 below depicts PG&E's VM Distribution Inspection process.

FIGURE PG&E-8.2.2-4:
PG&E'S VM DISTRIBUTION INSPECTION PROCESS



8.2.2.2.2 Distribution Second Patrol

Process

In accord with regulatory requirements and/or PG&E VM Second Patrol Procedure (TD-7102P-23), the VM Second Patrol program performs scheduled patrols approximately six months offset from the routine patrol on overhead primary and secondary distribution facilities. The primary target for secondary patrols is HFTD and HFRA but exceptions and additional areas are included to appropriately address vegetation associated risks. The objective of the Second Patrol is to maintain radial clearance between vegetation and conductors by identifying trees that will encroach within the MDRs and by identifying dead, dying, and declining trees that may fail and strike conductors. PG&E has implemented a plan to complete the identified dead/dying tree work within 180 days for HFTD areas and within 365 days for non-HFTD areas.

Frequency or Triggers

Second Patrol occurs approximately six months offset from Routine VM patrols on overhead primary and secondary distribution facilities.

Accomplishments

PG&E describes accomplishments in Section 8.2.2.2.1.

Roadblocks

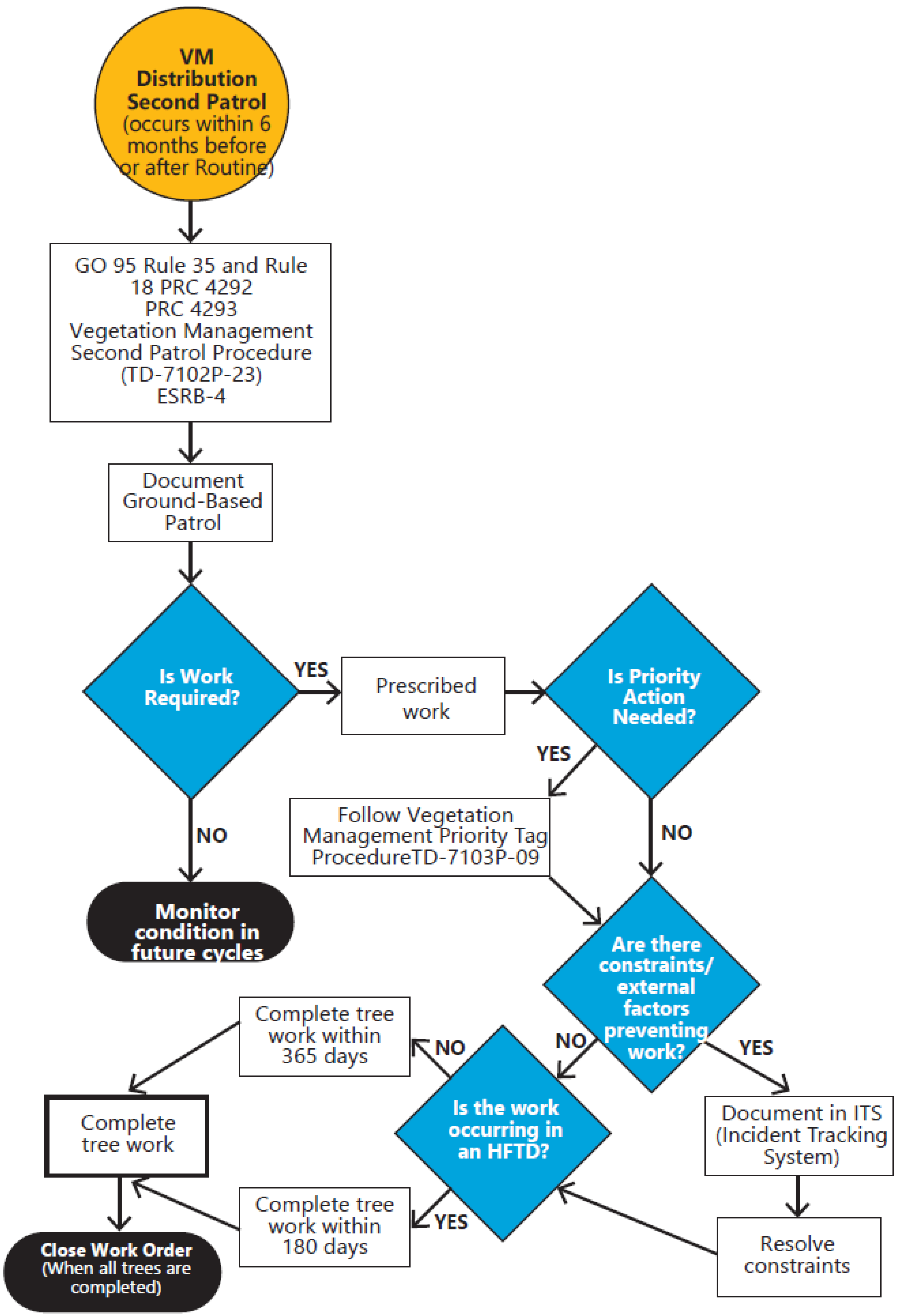
PG&E describes roadblocks in Section 8.2.2.2.1.

Updates

See AOC Focused Tree Inspection Program, VM-03, in Table 8-12 above.

Figure PG&E-8.2.2-5 below depicts PG&E's VM Distribution Second Patrol process.

FIGURE PG&E-8.2.2-5:
PG&E'S VM DISTRIBUTION SECOND PATROL PROCESS



8.2.2.2.3 VM for Operational Mitigations

Process

This is a new transitional program for 2023 stemming from the conclusion of the EVM program. This program is intended to help reduce outages and potential ignitions using a risk-informed, targeted plan to mitigate potential vegetation contacts based on historic vegetation outages on EPSS-enabled circuits. PG&E will initially focus on mitigating potential vegetation contacts in CPZs that have experienced vegetation caused outages. Scope of Work will be developed by using EPSS and historical outage data and vegetation failure from the WDRM v3 risk model. EPSS-enabled devices vegetation outages extent of condition inspections may generate additional tree work.

Frequency or Triggers

Workplan to reduce customer impacts due to vegetation outages on EPSS enabled devices. If at any point PG&E determines this program does not effectively support efforts to reduce customer impacts due to Vegetation Outages on EPSS when compared to other viable approaches, PG&E will pause or discontinue the VMOM efforts.

Accomplishments

This is a new program so there are no accomplishments to report.

Roadblocks

This is a new program so there are no roadblocks to report.

Updates

This is a new program so there are no updates to report.

VM for Operational Mitigations is a new transitional program starting in 2023. As such, we are still developing our inspection process and, therefore, do not have a process flow chart to provide at this time.

This initiative also supports VM Fall-in Mitigation. Addition information about this initiative is provided in Section 8.2.3.4 below.

8.2.2.2.4 Tree Removal Inventory

Process

This is a new transitional program for 2023 stemming from the conclusion of the EVM program. This program is intended to work down trees previously identified. PG&E estimates that our EVM inventory included more than 300,000 trees at the end of 2022. Under the Tree Removal Inventory program, we remove, or re-inspect trees identified in the EVM program. Based on this on-going re-inspection and evaluation work, we will develop annual risk-ranked work plans and mitigate the highest risk-ranked circuit segments or CPZs first. We plan to address all trees in the inventory in a multi-year program.

Frequency or Triggers

Workplan to remove or re-evaluate trees previously identified on EVM. If at any point PG&E determines this program does not effectively support efforts to remove or re-evaluate trees identified to EVM when compared to other viable approaches, PG&E will pause or discontinue the TRI efforts.

Accomplishments

This is a new program so there are no accomplishments to report.

Roadblocks

This is a new program so there are no roadblocks to report.

Updates

This is a new program so there are no updates to report.

Tree Removal Inventory is a new transitional program starting in 2023. As such, we are still developing our inspection process and, therefore, do not have a process flow chart to provide at this time.

This initiative also supports VM Fall-in Mitigation. Addition information about this initiative is provided in Section 8.2.3.4 below.

8.2.2.2.5 Focused Tree Inspections

Utility Initiative Tracking ID: VM-03; VM-11

Process

This is a new transitional program for 2023 stemming from the conclusion of the EVM program. PG&E is developing AOCs to better focus VM efforts to address high risk areas that have experienced higher volumes of vegetation damage during PSPS events, outages, and/or ignitions. We have conducted a county-by-county review with regional SMEs and used this information to develop polygons where focused vegetation inspections can be evaluated to determine appropriate counties to prioritize pilot(s). Focused Tree Inspection plans will be piloted in at least one area. The pilot will develop and implement guidelines that inform inspections

Frequency or Triggers

In Q2 2023, we will start a pilot. The lessons learned from the pilot will be used to further refine the program and determine if PG&E will roll out the program systemwide.

Accomplishments

The Area of Concern first draft has been developed. As listed above, the pilot will start in Q2 2023.

Roadblocks

This is a new program so there are no roadblocks to report.

Updates

This is a new program so there are no updates to report.

Focused Tree Inspections is a new transitional program starting in 2023. As such, we are still developing our inspection process and, therefore, do not have a process flow chart to provide at this time.

This initiative also supports VM Fall-in Mitigation. Addition information about this initiative is provided in Section 8.2.3.4 below.

8.2.2.2.6 Discontinued Programs

The EVM Program concluded at the end of 2022. PG&E will continue to strengthen our other existing VM programs. PG&E is transitioning the maintenance of enhanced clearances that were achieved in EVM to Routine VM patrols. We established routine maintenance requirements for electric distribution circuits where EVM scope clearances have been performed (in HFTD designated areas) and passed by work verification. The requirements have been documented in Utility Bulletin EVM Transition to Distribution Routine Patrol (TD-7102P-01-B026).

8.2.2.3 Vegetation Inspections – Substations

8.2.2.3.1 Defensible Space Inspection

Utility Initiative Tracking ID: VM-05; VM-06; VM-07

Process

PG&E assesses the area around Electric Substations in HFTD and HFRA areas to identify potential flammable fuels and vegetation for removal.[139] The removal minimizes the potential for ignition spread outside of substation facilities and provides improved structure defense capability for firefighting purposes by ensuring that there is a safe distance between vegetation and critical infrastructure. The identification and removal of vegetative fuels and achieving defensible space is described by California PRC Section 4291. The intent of defensible space inspections is to identify areas of vegetation related fire spread potential from an internal ignition event propagating outside the substation. In addition to outward fire spread mitigation, achieving utility defensible space also provides protection against substation infrastructure incoming from an incoming fire. Inspections are performed annually at all HFTD/HFRA substation locations and are prioritized for execution ahead of the wildfire season~~.~~

Frequency or Trigger

PG&E inspects the areas around Electric Substations in HFTD and HFRA annually. They are prioritized for execution ahead of the wildfire season. Table 8.2.2-1 shows the number of substation defensible space inspections planned from 2023-2025.

TABLE PG&E-8.2.2-1:
2023 SUBSTATION DEFENSIBLE SPACE INSPECTIONS

	2023	2024	2025
EO Transmission Substation	131	131	131
EO Distribution Substation	55	55	55
Hydro Power Generation (PG) Substations	61	61	61

Accomplishments

In 2022, Electric Operations (EO) and Power Generation established and operated similar but independent defensible space procedures; Substation Fire Hardening (LAND-4001P-01) and Power Generation Powerhouse and Switchyard Defensible Space (LAND-5201P-01). PG&E intends to combine both utility procedures, consolidating them into a singular procedure to be implemented in 2024. The new

139 After cutting back vegetation, PG&E may take the debris off 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 defense between vegetation and critical infrastructure.

procedure will include an evaluation of the risk associated with unique situations at co-located Power Generation and EO substation sites that inhibit the ability to achieve full defensible space. Included in the revised procedure will be an evaluation process including Safety and Infrastructure Protection Team (SIPT) members, Power Generation and substation fire marshals, and Natural Resource Management (NRM) team members who will evaluate the risk and make recommendations if further mitigations are required.

We also bundle Substation overhead vegetation maintenance with electric overhead VM to improve efficiency.

Roadblocks

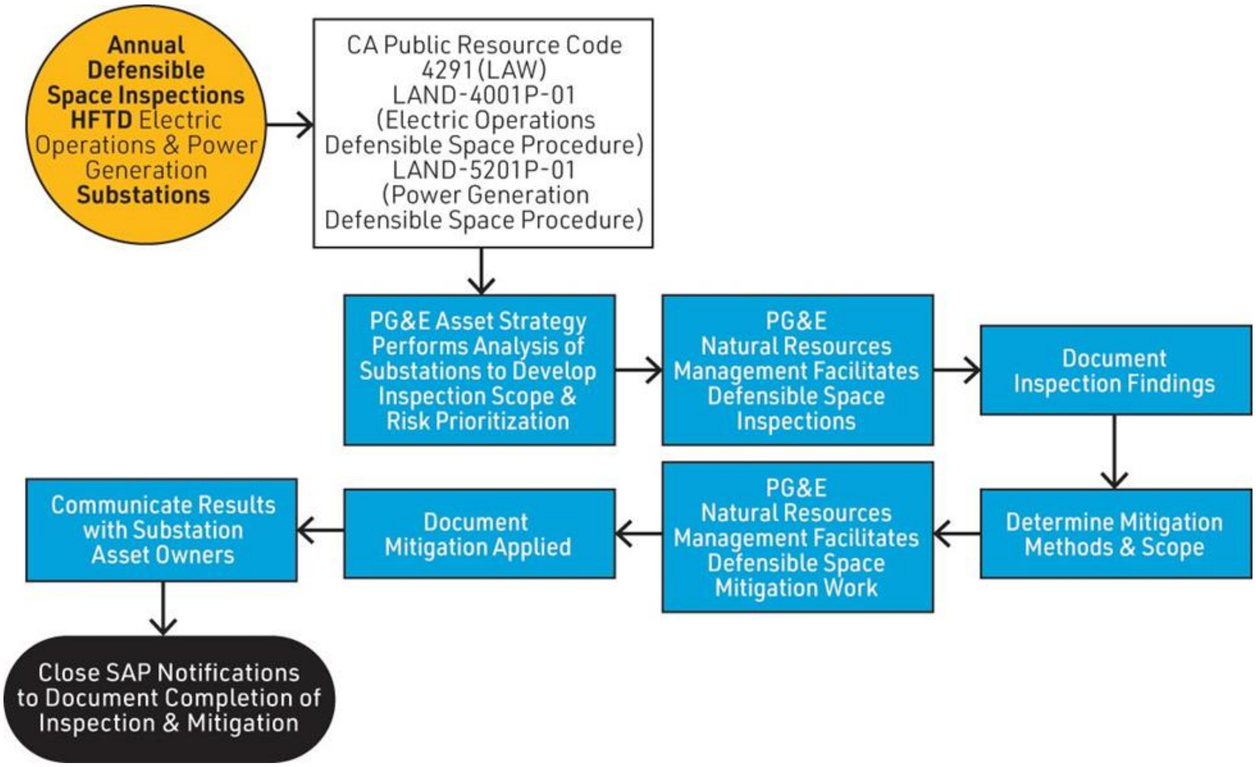
Landowner related issues continue to prevent PG&E from achieving 100 percent defensible space completion status at locations where substation defensible space zones extend into privately owned property.

Updates

For 2023, an additional clearance zone will be added to the Defensible Space requirements within PRC 4291. In 2023, Defensible Space is defined by three zones of clearance whereas in 2022 there were two zones. Starting in 2023 and beyond the first zone (0-5 ft.) from energized equipment or building is referred to as Zone 0 or the “Ember-Resistant Zone” and is intended to be void of any combustibles. The second zone (5-30 ft) surrounding energized equipment and building is called the “Clean Zone” and in most cases (with minimal exception) is clear of trees and most vegetation. The third and final zone of clearance (30-100 ft) is the “Reduced Fuel Zone” where vegetation is permitted if it is reduced or thinned and maintained regularly and within the requirements listed within PG&E Procedure LAND-4001P-01 and LAND-5201P-01.

Figure PG&E-8.2.2-6 below depicts PG&E's VM Substation process.

FIGURE PG&E-8.2.2-6:
PG&E'S VM SUBSTATION PROCESS 76



8.2.3 Vegetation and Fuels Management

In this section, the electrical corporation must discuss the following mitigation initiatives associated with vegetation and fuels management:

1) *Pole Clearing;*
2) *Wood and Slash Management;*
3) *Clearance;*
4) *Fall-in mitigation;*
5) *Substation defensible space;*
6) *High-risk species;*
7) *Fire resilient ROW; and*
8) *Emergency response VM.*

In the following subsections, the electrical corporation must provide an overview of its vegetation and fuels management initiatives. These overviews should include figure(s) that depict the workflow and decision process used for vegetation and fuels management. Figure 8-3 provides an example of the appropriate level of detail for tree trimming and removal.

In addition to figure(s), the electrical corporation must provide a narrative overview of each vegetation and fuels management initiative. The discussion must include the following:

Utility Initiative Tracking ID

- *<u>Overview of the Initiative</u>: A brief description of the initiative including reference to related objectives and targets.*
- *<u>Governing Standards and Electrical Corporation Standard Operating Procedures</u>: Reference to the appropriate code and electrical corporation procedure. If any standard exceeds regulatory requirements, the electrical corporation must reference the document that the electrical corporation uses as a basis for exceeding the regulatory requirements.*
- *<u>Updates to the Initiative</u>: Changes to the initiative since the last WMP submission and a brief explanation as to why those change were made. Discuss any planned improvements or updates to the initiative and the timeline for implementation.*

8.2.3.1 Pole Clearing

In this subsection, the electrical corporation must provide an overview of pole clearing activities, including:

- *Pole clearing per PRC Section 4292; and*
- *Pole clearing outside the requirements of PRC Section 4292 in Local Responsibility Areas inside HFTD and HFRA (e.g., pole clearing performed outside of the SRA).*

Pole Clearing per PRC 4292 and PUC 8386

Utility Initiative Tracking ID: VM-02

Overview of Initiative

PG&E performs removal/clearing of vegetation around select Transmission and Distribution poles and towers in accordance with PRC Section 4292, to maintain a firebreak of at least 10 ft in radius (out from the pole) up to 8 ft up from the ground per Title14 CCR 1254. These requirements apply in the SRA during designated fire season. PRC Section 4292 applies to SRA and has been adopted by Region 5 of the United States Forest Service (USFS), and mandates pole clearing requirements for equipment not otherwise exempted in Title 14 CCR 1255.

Additional firebreaks are maintained at non-SRA, non-Federal Responsibility Area (FRA) poles in areas of HFTD and PG&E's HFRA for conformance with PUC 8386. These additions are based on PG&E guidance (e.g., risk reduction work) or through local agreements. The locations are intended to reduce risk, improve access to equipment, allow for safe Supervisory Control and Data Acquisition operations, enhance public safety, supplement other mitigations, and protect assets from wildfires regardless of cause at equipment locations.

Governing Standards and Electrical Corporation Standard Operating Procedures

- Vegetation Control Program Standard (TD-7112S); and
- Vegetation Control Procedure (TD-7112P-01).

PG&E has also developed multiple job aids supporting pole clearing such as:

- Fire Risk Assessment: Vegetation Control Pole Clearing (TD-7112P-01-JA01);
- Pole Work Status Report Types (TD-7112P-01-JA02).

Updates to Initiative

For updates to Utility Defensible Space (UDS), a program PG&E developed in 2021 that addresses reduction or adjustment of dead and live fuels, see ACI PG&E-22-23, "Reduce Necessity for UDS Program."

8.2.3.2 Wood and Slash Management

In this subsection, the electrical corporation must provide an overview of how it manages all downed wood and “slash” generated from VM activities, including references to applicable regulations, codes, and standards.

Reduction or adjustment of dead fuel, including all downed wood and “slash” generated from VM activities

Overview of Initiative

PG&E’s VM Programs define debris as material less than 4 inches in diameter and large wood as material greater than 4 inches in diameter. PG&E is required to reduce or adjust live fuels as they are generated from programs developed to comply with PRC 4291, GO 95 Rule 35 and PUC 8386.

Debris less than 4 inches in diameter that is generated during pruning activities are chipped or lopped and scattered on the property in accordance with applicable regulations. Chips are left on site or removed off site based on owner preferences. Typically, we chip debris where access allows, otherwise we lop and scatter.

The Wood Management program addresses large wood generated by PG&E’s VM activities. This includes post-fire work activities, and wood generated by the EVM Program. Wood Management is a voluntary program in which property owners must opt in to participate. The program is designed to help alleviate the potential burden caused by the presence of larger diameter wood on customer properties resulting from PG&E activities. Wood larger than 4 inches in diameter belong to the landowner and wood management varies based on the owner’s preference.

Governing Standards and Electrical Corporation Standard Operating Procedures

- Best Management Practices (BMP) for Vegetation Management Activities (TD-7102P-01-JA01); and
- Wood Management (TD-7102P-26).

Updates to Initiative

There are no updates to this initiative.

8.2.3.3 Clearance

In this subsection, the electrical corporation must provide an overview of clearance activities, including:

- *Clearances established in excess of the minimum clearances in Table 1 of GO 95; and*
- *The bases for the clearances established.*

These overviews should include figure(s) that depict the workflow and decision process used for vegetation and fuel management.

In addition to figure(s), the electrical corporation must provide a narrative overview regarding vegetation and fuel management initiative. The discussion must include the following:

Overview of Initiative

PG&E's EVM Program established clearances exceeding compliance with GO 95 Rule 35 and PRC, Section 4293, which may be accessed in Appendix E. As discussed in Section 8.2.2.2.3 above, we concluded EVM at the end of 2022. We will continue to maintain clearances that had been established under the EVM Program via the Routine Distribution Program.

PG&E will continue to address our EVM inventory under the new Tree Removal Inventory Program. Tree Removal Inventory is a long-term program intended to eventually work down trees, either through removal or reinspection, that were previously identified (see Section 8.2.3.4) in the EVM program.

Governing Standards and Electrical Corporation Standard Operating Procedures

When performing work in the HFTD, PG&E complies with Appendix E of GO 95. The radial clearances set forth in Table 1, Cases 13 and 14 shown in Table PG&E-8.2.3-1: 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.

The actual clearance obtained is determined on an individual tree basis and 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 SRA lands, pursuant to PRC Sections 4102 and 4293.

TABLE PG&E-8.2.3-1:
RADIAL CLEARANCES, 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 V	4 ft.	12 ft.
Radial clearances for any conductor of a line operating at 72,000 or more volts, but less than 110,000 V	6 ft.	20 ft.
Radial clearances for any conductor of a line operating at 110,000 or more volts, but less than 300,000 V	10 ft.	30 ft.
Radial clearances for any conductor of a line operating at 300,000 or more volts	15 ft.	30 ft.

(a) Case 13 of Table 1: Refers to GO 95, Appendix E, Table 1. Case 13 is Radial clearance of bare line conductors from tree branches or foliage. A link to Table 1 is provided in Note C.

(b) Case 14 of Table 1: Refers to GO 95, Appendix E, Table 1. Case 14 is Radial clearance of bare line conductors from vegetation in the Fire Threat Districts. A link to Table 1 is provided in Note C.

(c) GO 95 Table 1 (ca.gov).

Updates to Initiative

As discussed in Section 8.2.2.2.3, PG&E concluded our Enhanced VM Program in 2022 and we are implementing three new VM Programs described in Section 8.2.3.4 below. We ended the Enhanced VM Program because we determined that we could more effectively manage wildfire risk through a combination of Operational Mitigations, primarily EPSS, and the new VM Programs discussed in Section 8.2.3.4 below.

8.2.3.4 Fall-In Mitigation

In this subsection, the electrical corporation must provide an overview of its actions taken to identity and remove or otherwise remediate trees that pose a high risk of failure or fracture that could potentially strike electrical equipment, (e.g., danger trees or hazard trees).

Utility Initiative Tracking ID: VM-04

Overview of Initiative

PG&E's Regulatory Compliance work starts with an annual patrol of all PG&E distribution lines to support compliance with the CPUC's GO 95 Rule 35, and California PRC Section 4293. Every year, we inspect trees along our entire distribution system—approximately 80,000 miles of overhead distribution lines.

PG&E also performs scheduled Second Patrols with an approximate six-month offset from the routine patrol on overhead primary and secondary distribution facilities. The primary target for Second Patrols is HFTD and HFRA but other areas are also included to address specific risks associated with vegetation.

The objective of the Second Patrol is to maintain radial clearance between vegetation and conductors by identifying trees that will encroach within the MDRs and by identifying dead, dying, and declining trees that may fail and strike conductors.

See Section 8.2.2 for more information about our VM inspection programs.

In 2023, PG&E is implementing three new VM Programs that support fall-in mitigations: VM for Operational Mitigations; Tree Removal Inventory; and Focused Tree Inspections. These programs are described in Section 8.2.2.2.3, 8.2.2.2.4, and 8.2.2.2.5 above.

Governing Standards and Electrical Corporation Standard Operating Procedures

- CPUC GO 95 Rule 35; and
- California PRC Section 4293.

We are developing new standards for these programs. We anticipate completing them in 2023.

Updates to Initiative

PG&E is restructuring our VM Program starting in 2023. Based on recent data and analysis, the risk reduction of the EVM Program is less than the risk reduction from the EPSS program that was introduced in 2021. Additional Operational Mitigations such as PVD and DCD will also help to mitigate risk previously prescribed to EVM. As a result, PG&E concluded the EVM Program at the end of 2022 and is introducing the three new VM initiatives described above: VM for Operational Mitigations; Tree Removal Inventory; and Focused Tree Inspections.

8.2.3.5 Substation Defensible Space (Mitigation)

In this subsection, the electrical corporation must provide an overview of its actions taken to reduce the ignition probability and wildfire consequence due to contact with substation equipment. These overviews should include figure(s) that depict the workflow and decision process used for vegetation and fuel management.

In addition to figure(s), the electrical corporation must provide a narrative overview regarding vegetation and fuel management initiative. The discussion must include the following:

- *Overview of Initiative: Brief description of the initiative including the objective and the risk targeted by the initiative.*
- *Governing Standards and Electrical Corporation Standard Operating Procedures: Reference to the appropriate code and electrical corporation program/process. If any standard exceeds regulatory requirements, this must include reference to the basis document for the electrical corporation-specific values.*
- *Updates to Initiative: Changes to the initiative since the last WMP submission and a brief explanation as the why those changes were made. Discuss any planned improvements or updates to the initiative and timeline for implementation.*

As necessary, the electrical corporation must provide additional details in Appendix B

Overview of Initiative

PG&E assesses the area around Electric Substations in HFTD and HFRA areas to identify potential flammable fuels and vegetation for removal. This removal minimizes the potential for ignition spread outside of facilities and provides improved structure defense capability for firefighting purposes by ensuring that there is a safe distance between vegetation and critical infrastructure. We identify and remove vegetative fuels and achieve defensible space as described by PRC Section 4291.

The intent of defensible space inspections is to identify areas of fire spread potential from an internal ignition event spreading outside the substation. In addition to outward fire spread mitigation, achieving utility defensible space also provides mitigation associated with minimizing substation infrastructure impacts from an incoming fire. Inspections are performed annually at all HFTD and HFRA substation locations and are prioritized for execution ahead of the wildfire season.

For 2023, an additional clearance zone will be added to Defensible Space requirements within PRC 4291. In 2023, Defensible Space is defined by three primary zones of clearance whereas in 2022 there were two zones. Starting in 2023 the first zone (0-5 ft.) from energized equipment or building is referred to as Zone 0 or the “Ember – Resistant Zone” and is intended to be void of any combustibles. The second zone (5-30 ft.) surrounding energized equipment and building is called the “Clean Zone” and in most cases (with minimal exceptions) is clear of trees and most vegetation. The third and final zone of clearance (30-100 ft.) is the “Reduced Fuel Zone” where vegetation is permitted if it is reduced or thinned and maintained regularly and within the requirements listed within Substation Fire Hardening Procedure (LAND-4001P-01), which may be accessed in Appendix E.

Substation Defensible Space Mitigations

This substation utility defensible space program includes the removal of dead, dying, or diseased vegetation, where permitted, based on results and findings from substation defensible space inspections described in Section 8.2.2.3.1. Remaining vegetation is mowed, pruned, and trimmed to reduce ladder or flash fuels. Issues identified during utility defensible space inspections become work orders for Electric Operations (EO) and Inspection Reports for Power Generation and in both instances are executed to mitigate any defensible space issues that could pose a vegetation related ignition risk.

VM work includes mechanical weed abatement, tree trimming, newly identified hazard trees, and brush and debris removal in accordance with utility defensible space recommendations. Inspection and mitigation activities are prioritized based on elevation and annual fuel growth in which lower elevations are inspected first as they have a higher rate of growth and dry out earlier in the season while higher elevations grow slower and later into the year. All mitigation activities are performed in accordance with Substation Fire Hardening Procedure (LAND-4001P-01) and Power Generation Powerhouse and Switchyard Defensible Space Procedure (LAND-5201P-01).

In 2022, EO and Power Generation established and operated similar, but independent, defensible space procedures – Substation Fire Hardening Procedure (LAND-4001P-01) and Power Generation Powerhouse and Switchyard Defensible Space Procedure (LAND-5201P-01). PG&E intends to combine both utility procedures into a singular procedure that will be implemented in 2024. The new procedure will include an evaluation of the risk associated with unique situations at Power Generation and EO substation sites that inhibit the ability to achieve full defensible space as described. Included in the evaluation process are SMEs in Power Generation, substation, SIPT, and NRM who will evaluate the unique wildfire risk factors and make recommendations to further mitigate risks.

Governing Standards

- PRC Section 4291;
- Substation Fire Hardening Procedure (LAND-4001P-01); and
- Power Generation Powerhouse and Switchyard Defensible Space Procedure (LAND-5201P-01).

Updates to Initiatives

There are no updates to this initiative.

8.2.3.6 High-Risk Species

In this subsection, the electrical corporation must provide an overview of its actions, such as trimming, removal, and replacement, taken to reduce the ignition probability and wildfire consequence attributable to high-risk species of vegetation.

These overviews should include figure(s) that depict the workflow and decision process used for vegetation and fuel management.

In addition to figure(s), the electrical corporation must provide a narrative overview regarding vegetation and fuel management initiative. The discussion must include the following:

Overview of Initiative

PG&E seeks to identify trees at elevated risk of failing and striking our electrical facilities. Species is just one factor of many that PG&E takes into account to reliably identify the higher risk trees.

PG&E completed a Targeted Tree Species (TTS) study in 2022 (Attachment 2023-03-27_PGE_2023_WMP_R0_Section 8.2.3_Atch01). The purpose of PG&E's TTS Study was to identify species that are more likely to fail near PG&E facilities, thereby creating potential wildfire ignitions. The study involved an analysis of tree mortality rates related to precipitation and the impacts of seasonal precipitation on growth.

We have evaluated the recommendations in the final report and continue to analyze them and consider our go-forward actions.

Governing Standards and PG&E Operational Procedures

There are no governing standards for high-risk species.

Updates to Initiative

PG&E describes updates to the high-risk species initiative in the "Overview of Initiative" section above.

8.2.3.7 Fire Resilient ROWs

In this subsection, the electrical corporation must provide an overview of its actions taken to promote vegetation communities that are, sustainable, fire resilient, and compatible with the use of the land as an electrical corporation ROW. It must also provide an overview of its actions to control vegetation that is incompatible with electrical equipment and with the use of the land as an electrical corporation ROW. This may include, but is not limited to, the following activities: the strategic use of herbicides, growth regulators, or other chemical controls; tree-replacement programs; promotion of native shrubs; prescribed fire; or fuel treatment activities not covered by another initiative.

These overviews should include figure(s) that depict the workflow and decision process used for vegetation and fuel management.

In addition to figure(s), the electrical corporation must provide a narrative overview regarding vegetation and fuel management initiative. The discussion must include the following:

Overview of Initiative

For other Fire Resilient ROW activities, please see Section 8.2.3.1

Integrated VM for transmission, which is not compliance driven, promotes desirable, stable, low-growing plant communities that resist invasion by tall growing tree and brush species through appropriate, environmentally sound, and cost-effective control methods. IVM control methods include a combination of chemical, biological, cultural, mechanical, and/or manual treatments. Long-term, effective IVM transitions the vegetative community to a composition of low growing, compatible native species. IVM follows Transmission Integrated Vegetation Management (TIVM) Utility Procedure (TD-7103P-04).

IVM focuses on established Transmission-ROW corridors. ROW corridors are placed into the IVM Program typically one to two years following reclamation and are periodically reworked when regrowth threshold triggers are met or exceeded. Where feasible, the IVM Program implements wire zone border zone management to promote 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.

Threshold triggers for implementing this procedure include incompatible vegetation exceeding 3 ft. in height and/or when incompatible vegetation is greater than 50 percent ground coverage within the ROW. Other triggers include the need to control vegetation around transmission towers, poles and guy wires see Section 8.2.2.1.

In 2023, PG&E will pilot other new initiatives. For example, we are purchasing access to robust land management analysis for the Tahoe National Forest (which includes PG&E assets) and land around other PG&E assets in nearby Nevada and Placer

Counties. This data will help us to better understand the benefits of fuels management for public safety and asset defense in specific locations.[140]

In addition to evaluating the benefits of wildfire protection for different land treatment scenarios, this analysis will also consider the benefits created by ecological forest fuels treatment including carbon sequestration, water security, biodiversity conservation, biomass availability for conversion investment, and recreation.

The data from the studies may inform future USFS applications, North American Electric Reliability Corporation applications, and/or private land management activities by third parties and/or PG&E and could lay the foundation to evaluate high value hazardous fuels reductions.

PG&E is also conducting technology demonstrations through its Electric Program Investment Charge (EPIC) Program, specifically EPIC 3.47, "Operational Vegetation Management Efficiency Through Novel Onsite Equipment," to create fuel management efficiencies by testing innovative solutions to reduce wood management costs and improve associated environmental and safety outcomes. Five technology innovators were chosen to demonstrate solutions which have the potential to materially reduce wood management costs, improve economics for clean wood products derived from non-salable timber, and to reduce, displace, and/or to remove greenhouse gas and criteria pollutants emissions associated with wood transportation and conversion.

Governing Regulations and PG&E Operational Procedures

- PG&E Operational Standard: Transmission Right-of-Way (ROW) Maintenance and ROW Expansion Programs Standard (TD-7111S).
- PG&E Operational Procedure: Transmission Integrated Vegetation Management Procedure (TIVM) Procedure (TD-7103P-04).

Updates to Initiative

The 2023 IVM pilot initiatives are described in the Overview of Initiative section above.

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140 The scale of the analysis depends on the funding received from PG&E and other stakeholders. With additional funding the study will expand into highly populated and at-risk landscapes in Nevada and Plumas counties.

8.2.3.8 Emergency Response Vegetation Management

In this subsection, the electrical corporation must provide an overview of the following two emergency response VM activities:

- *Activities based on weather conditions:*
  - *Planning and execution of VM activities, such as trimming or removal, executed based on and in advance of Red Flag Warning (RFW) or other weather condition forecast that indicates an elevated fire threat in terms of ignition probability and wildfire potential; and*
- *Post-fire service restoration:*
  - *VM activities during post-fire service restoration, including, but not limited to, activities or protocols that differentiate post-fire VM from programs described in other WMP initiatives; supporting documentation for the tool and/or standard the electrical corporation uses to assess the risk presented by vegetation after a fire; and how the electrical corporation includes fire-specific damage attributes in its assessment tool/standard. The description of such activities must differentiate between those emergency actions initiated to restore power while active fire suppression is ongoing and actions that occur following active fire suppression during the post-fire suppression repair and rehabilitation phases of fire protection operations.*
- *These overviews should include figure(s) that depict the workflow and decision process used for vegetation and fuel management.*
- *In addition to figure(s), the electrical corporation must provide a narrative overview regarding vegetation and fuel management initiative. The discussion must include the following:*

Overview of Initiative

Executing high priority vegetation work in impacted areas can reduce the potential for ignitions in RFW and urgent weather situations.

Reducing damage to facilities in advance of restoration will reduce the duration of PSPS and/or EPSS events.

<u>RFW Preparation When Possible</u>

Areas identified as subject to RFW conditions are based on the National Weather System’s Meteorological Models.

All trees identified for work by pre-inspectors are prioritized. If vegetation is determined to be an immediate risk to PG&E facilities, described as a Priority 1 Condition in the VM Priority Tag Procedure (TD-7102P-17), the condition will be mitigated within 24 hours of identification as long as conditions are safe for the tree crew to proceed with work.

Vegetation identified as pending Priority 2 work within the RFW area will be reviewed and mitigated as outlined in the VM Priority Tag Procedure (TD-7102P-17).

Wildfire Response and Restoration – Short-Term First Response and Restoration Support

When a wildfire impacts PG&E's electric overhead assets there are different response phases based on the size of the fire, intensity of burn, and damage to PG&E assets. Restoration is the first response phase. During this first phase VM activities are focused on: ensuring public safety by mitigating vegetation that is an imminent threat to PG&E assets; and supporting electric crews by removing vegetation and providing access to restore service to customers. The second phase of VM activities are focused on reliability by mitigating hazard trees that have the potential to fail into PG&E assets. PG&E performs a hazard tree assessment of the burned area to determine whether trees pose a threat to electric assets and if they should be abated.

PG&E is developing a standard for assessment criteria that will be used when evaluating trees within a wildfire impacted area. The standard will contain assessment criteria to identify hazard trees for mitigation and to reduce the risk of a tree failing into PG&E facilities within a wildfire impacted area.

Governing Standards and Electrical Corporation Standard Operating Procedures

- Vegetation Management Priority Tag Procedure (TD-7102P-17); and
- Preventing and Mitigating Fires While Performing PG&E Work Procedure (TD-1464S).

As discussed in ACI PG&E-22-27, we are developing a Vegetation Management Post-Wildfire Standard. Once the Post-Wildfire Standard is complete we will develop a Post-Wildfire Procedure. We cannot provide a figure depicting the workflow and decision-making processes for Post-Wildfire response and restoration until the procedure is complete.

Updates to Initiative

As described above, PG&E is developing a standard for assessment criteria that will be used when evaluating trees within a wildfire impacted area.

8.2.4 VM Enterprise System

In this section, the electrical corporation must provide an overview of Inputs to, operation of, and support for a centralized VM enterprise system updated based upon inspection results and management activities such as trimming and removal of vegetation. This overview must include discussion of:

Utility Initiative Tracking ID: VM-12

PG&E VM currently uses multiple centrally managed- systems to document planned and completed vegetation work. The use of multiple systems results in less visibility into the work being performed at different times and in different locations. To solve this issue, we are building a tool that will be used to manage our various program requirements and to support our work processes.

Below we describe the current roll-out plan by phase. Based on Information Technology (IT) development, user feedback, and direction from leadership, the phases may change as the program evolves.

Phase 1, Release 1 occurred in the second quarter of 2022 and included Distribution Routine VM work management and Second Patrol work management. Work management components allow tracking of work that is planned, scheduled, and completed.

Phase 1, Release 2 added additional functionality for Routine VM and Second Patrol work programs in October 2022. This included additional functionality for Pre-Inspectors and Tree Crews that are supporting Routine and Second Patrol programs.

Currently, Phase 2 includes integration of the Pole Clearing program and is planned for release in 2023. This phase will include integration with work management (work planning, scheduling, tracking, and verification).

One VM tool improvements will continue during the WMP cycle.

<u>Vegetation Inventory and Condition Database(s)</u>

The vegetation databases include the Vegetation Management Database (VMD) and Project Management Database (PMD). Data included in the VMD/PMD are vegetation points, alert information (e.g., bad dog, access information, etc.), and parcel contact information. Additional reference data that VM relies on includes reference data from other PG&E systems such as asset information.

<u>Internal Documentation</u>

The One VM Tool development team created an internal SharePoint website for PG&E and contract VM staff with supportive tools such as user guides, quick reference cards, how-to videos, a training information hub, and a case management system where users can submit a ticket for issues they encounter.

Integration with Other Systems

VM may integrate its One VM tool with other lines of business in a future release. At this time, no integration with other lines of business is planned for the 2023--2025 period.

Procedures for Updating the Enterprise System and Planned Updates.

One VM will provide map based-work execution, monitoring, and validation applications available on iOS mobile devices. The One VM Project is part of the Strategic Priorities List for VM Leadership Wildfire Mitigation Program centralized vegetation inventory system. PG&E started implementing the One VM Tool with the Routine and Second Patrol programs. We are continuing to update and improve the tool based on user feedback and direction from leadership. As the VM One Tool is developed, IT is migrating information from PG&E's six legacy databases into it.

Inventories of known reference data were added into the One VM Tool so that users can enter inspection and work records and to ensure that users are transitioning to and using the One VM Tool on a consistent basis as the roll-out continues, rather than returning to legacy databases.

As programs are successfully incorporated into the One VM Tool, the legacy databases will no longer be available for regular use. PG&E will retain the legacy databases for record keeping purposes. PG&E will continue to implement the transition into an enhanced and streamlined centralized system to maintain its VM records.

Integration with the Auditing Systems

Enterprise systems and QA/QC systems are integrated through use of unique location identifiers. Additionally, mitigation tracking mechanisms specific to the quality management system have been implemented for multi-step integration with enterprise systems.

Changes since the Last WMP

Since the last WMP, PG&E rolled out- the One VM Tool Phase 1, Release 2 as described above and continues to develop plans for future releases.

8.2.5 Quality Assurance/Quality Control

In this section, the electrical corporation must provide an outline of QA/QC activities for VM. This overview must include:

- *Reference to procedures documenting QA/QC activities;*
- *How the sample sizes are determined and how the electrical corporation ensures the samples are representative;*
- *Who performs QA/QC (internal or external; is there a dedicated team, etc.) ;*
- *Qualifications of the auditors;*
- *Documentation of findings and how the lessons learned from those findings are incorporated into trainings and/or procedures;*
- *Any changes to the procedures since the last WMP submission and a brief explanation as to why those changes were made. Include any planned improvements or updates to the initiative and the timeline for implementation;*
- *Tabular information:*
  - *Sample sizes;*
  - *Type of QA/QC performed (e.g., desktop or field);*
  - *Resulting pass rates, starting in 2022; and*
  - *Yearly target pass rate for the 2023-2025 Base WMP cycle.*

Utility Initiative Tracking ID: VM-08

VM's Quality Management System is designed to provide multiple layers of defense against hazards and failures. These layers of defense—Quality Control/Work Verification (QC/WV), Quality Verification/Quality Assurance (QV/QA)—help build reliable, repeatable, and sustainable processes. Figure PG&E-8.2.5-1 below explains the different layers of our defense with the high-level details of coverage and scope of work.

FIGURE PG&E-8.2.5-1:
VM QUALITY MANAGEMENT

VM Quality Management System – Layers of defense

	Objective	Scope of work
Quality Control (QC) *[Work Verification (WV)]*	• Ensure completed inspections and tree work performed by VM Execution meet quality standards	• Work Verification assess completed inspections and tree work are compliant with PG&E's standards & procedures and Public Resource Code (PRC) sections 4292 and 4293, GO 95, Rule 35 • Field Quality Control (FQC) acts as a facilitator focused on the **people performing the work** • FQC PMs are deployed side-by-side with coworkers to evaluate whether work methods align with the respective program's standards & procedures
Quality Assurance (QA) *[Quality Verification (QV)]*	• Quality Verification: Ensure **work completed by WV and Execution** meets quality and compliance standards	• Quality Verification: **Targeted inspections** on work completed by Execution and WV to ensure no hazards or other critical failures were missed

Internal

1

Descriptions of each of the quality programs are provided below.

8.2.5.1 Quality Assurance and Quality Verification

Quality Verification Vegetation Management (QVVM): QVVM is the branch of QA responsible for validating effectiveness of VM quality programs, by auditing a statistically valid sample of "work verification complete" locations.

The procedures that the QVVM team follow will be revised in 2023. PG&E anticipates that the updated procedures will be complete by the end of the third quarter of 2023.

Sample sizes are determined using a 95 percent confidence level, 5 percent margin of error sampling calculation. QVVM samples will be sourced from completed work verification inspection locations randomized systemwide.

Audit findings are recorded in a system of record to ensure a robust feedback loop and capture opportunities for on-going program improvements.

Qualifications of the Auditors

QVVM activities/audits are supported by internal and external personnel.

Minimum qualifications for the auditors are:

- Minimum of 2 years of utility VM experience or related field of education;
- Tree identification skills and the ability to read maps;
- Must be able to work alone, outdoors in various weather conditions and terrain;
- Basic computer skills, knowledge of Device Operating System (iOS); and
- Must have ability to obtain an International Society of Arboriculture (ISA) Certification within one year of hire.

PG&E is developing a training path for QVVM team members to be completed by Q2 2023.

Changes Since the Last WMP

Previously, QVVM reviewed completed EVM work. QVVM reviewed a statistically valid sample of completed pre-inspection locations, completed work verification locations (where applicable), and completed tree work.

With the conclusion of EVM, and subsequent deployment of work verification on each of the primary VM Programs, QVVM will audit a statistically valid sample of completed work verification locations. This change was implemented as part of our ongoing efforts to implement multiple layers of defense within the VM quality management system.

Table 8-18-1 below shows PG&E's VM inspection programs, 2022 audit results, and annual target pass rates for 2023-2025.

TABLE 8-18-1:
VEGETATION MANAGEMENT QV PROGRAM

Inspection Program	2022 Sample Size[(a)]	Type of Audit	Audit Results 2022 [(c)]	Yearly Target Pass Rate for 2023[(d)]	Yearly Target Pass Rate for 2024[(d)]	Yearly Target Pass Rate for 2025[(d)]
Distribution	28,516 Locations	Field	91.3%[(b)]	N/A	N/A	N/A
Distribution VM – HFTD	N/A	Field	N/A	95%	95%	95%
Distribution VM – Non-HFTD	N/A	Field	N/A	N/A	N/A	N/A
Transmission	5,896 Locations	Field	94.2%	N/A	N/A	N/A
Transmission VM HFTD	N/A	Field	N/A	95%	95%	95%
Transmission Non HFTD	N/A	Field	N/A	N/A	N/A	N/A
Vegetation Control Pole Clearing	3,469 Poles	Field	90.3%	N/A	N/A	N/A
Vegetation Control Pole Clearing – HFTD	N/A	Field	N/A	95%	95%	95%
Second Patrol	12,952 Locations	Field	N/A	95%	95%	95%
Second Patrol – HFTD	N/A	Field	N/A	95%	95%	95%

(a) Sample calculations were done at the location level for QVVM Programs. Locations vary in geographic size and can have multiple trees within one location. Not all trees in a single location may be exclusively HFTD or Non-HFTD. For this reason, it is not possible to break out HFTD and Non-HFTD sample sizes for Distribution and Transmission.

(b) In 2022, the distribution score of 91.34 percent reflected both Maintenance Pre-Inspection/Tree Trimming (PI/TT) and Second Patrol (PI/TT).

(c) "N/A" in 2022 indicates that PG&E did not conduct an audit of the program.

(d) "N/A" in 2023-2025 indicates that PG&E does not plan to conduct an audit of the program during this time.

8.2.5.2 Quality Control

QC is the process of ensuring quality requirements are met. Work Verification is PG&E's QC Program. In addition, we further strengthen our quality control efforts through a Field Quality Control (FQC) Program.

Minimum sample sizes are determined using a 99 percent confidence level, 5 percent margin of error sampling calculation. QCWV samples will be sourced from completed Vegetation Management work locations randomized systemwide.

VM Quality Control

The QC Program has been designed and is implemented to ensure that post-VM execution work meets the applicable procedural scope as it relates to quality and regulatory compliance. User guides, procedures, and standards documents are in the development stage. PG&E anticipates completing these documents by the end of Q2 2023.

QC sample sizes will be based on statistically valid samples and subject to the completed work.

QC is performed by a dedicated internal team and supplemented by contract resources as needed.

Work Verifiers must meet the following qualification requirements:

- Bachelor's Degree in forestry or job-related discipline or equivalent experience;
- 3 years of job-related experience; and
- CA Class C License, or equivalent.

Additional desired Qualifications are ISA Certified Arborist, Tree Risk Assessment Qualification, and Utility Arborist.

QC has implemented a Training Path (formerly known as Structured Learning Path) for all internal and external work verification field personnel effective June 2022. On the internal VM SharePoint site, WV Supervisors can review the training expectations and training documents for work verification. The QC Training Path Summary also affirms that the QC Verifiers demonstrate both the knowledge and skills necessary to perform the role of a work verifier at periodic time intervals from their initial hire date.

The processes for tracking, reporting, and completing QC observations are in the development stage. PG&E anticipates completing these documents by the end of Q2 2023.

Previously, QC verifiers reviewed EVM work. With the conclusion of EVM, QC will be performed on Routine VM and may be performed on other VM Programs.

Table PG&E 8-18-2 below provides the 2022 QC audit results.

TABLE 8-18-2:
VEGETATION MANAGEMENT QC METRICS REPORT

Inspection Program	2022 Sample Size[(a)]	Type of Audit	Audit Results 2022
EVM	100% (1,924 miles)	Post-execution work completion	80.64% First Pass Rate
Routine VM – HFTD	N/A	Post-execution work completion	Did not perform
Routine VM – Non-HFTD	N/A	Post-execution work completion	Did not perform
Vegetation Control Pole Clearing	N/A	Post-execution work completion	Did not perform
Second Patrol	N/A	Post-execution work completion	Did not perform
Transmission VM HFTD	N/A	Post-execution work completion	Did not perform
Transmission VM Non- HFTD	N/A	Post-execution work completion	Did not perform

(a) 'N/A' indicates that, the program was not audited in 2022.

Field Quality Control

We developed a FQC Program that provides an additional layer of review for our VM Programs. The FQC team performs active side-by-side observations of employees and contractors performing vegetation work. The FQC teams evaluates whether observed work methods align with PG&E's standards and procedures. Observing work in real time allows us to focus on improving the quality of work and improving the knowledge and skills of the people performing it.

Currently, FQC observations are performed on Vegetation Management Inspectors (VMI) in the Routine VM and Second Patrol programs. FQC also observes Vegetation Control (Pole Clearing) Technicians (VCT).

FQC active observations are planned for the Routine VM and Transmission VM Programs. In addition, FQC will continue to support special quality review projects and look for opportunities improve VM performance.

FQC follows the processes documented in the draft Vegetation Management and Systems Inspection Quality Manual. The draft procedures will be updated in 2023.

FQC performs active observations targeting approximately 90 percent of individuals meeting eligibility criteria for the program being reviewed, which is influenced by execution production and resource volumes. FQC is performed by a dedicated internal PG&E team supplemented by contract resources.

Internal Field Quality Control Program Managers (FQCPM) must meet the following minimum qualification requirements

- Bachelor's Degree in forestry or job-related discipline or equivalent experience;
- 3 years of job-related experience; and
- California Class C License, or equivalent.

Required training for FQCPMs involves a series of web-based trainings and technical document reviews, facilitated by the FQCPM's leader or a delegate. The FQCPM Training Program must be completed within the first 12 months of onboarding to a FQCPM position. Training specifications are outlined in Vegetation Management and Systems Inspection Quality Manual.

FQC Assessment records (the FQCPM field observation) are captured in Survey123. Assessments are summarized in dashboards and metric reports are published on a regular basis. All findings are communicated to the execution teams to provide lessons learned and assist in process improvement. The FQC team has conducted Quality Learning Forums to support the execution teams improved awareness and performance.

The FQC team plans to expand its assessment process in 2023 to incorporate review of additional programs and personnel as shown in Table 8-18-3 below.

TABLE 8-18-3:
VM FIELD QC METRICS REPORT

Inspection Program	Sample Size[(a)]	Type of Audit	Audit Results 2022[(b)(c)(d)]	2023 Status	Yearly Target Pass Rate for 2023-2025
Routine Distribution	90 percent of eligible population (VMI)	Active side-by-side observations	Captured in the FQC Routine Distribution Metrics Report	Planned	88%
Second Patrol	90 percent of eligible population (VMI)	Active side-by-side observations	Captured in the FQC Second Patrol Metrics Report	Planned	88%
Transmission	90 percent of eligible population (VMI)	Active side-by-side observations	N/A	Planned	88%
Vegetation Control	90 percent of eligible population (VCT)	Active side-by-side observations	N/A	Planned	88%

(a) Eligibility is defined as individuals identified in the work execution system of record with activity above a defined threshold in Q1 of the calendar year. Individuals who are not active, offboarded, transferred to a different program, or are in a specialty role at the time the observation is attempted are not considered eligible.
(b) Audit results captured in the FQC metrics report are informational and not tabulated into a singular pass rate.
(c) "N/A" indicates that PG&E did not conduct an audit of the program.
(d) 'N/A' indicates that, the program was not audited in 2022.

8.2.6 Open 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 VM inspections that prescribe VM activities. This overview must include a brief narrative that provides:

Reference to procedures documenting the work order process;

- *A description of how work orders are prioritized based on risk;*
- *A description of the plan for eliminating work order backlogs (i.e., open work orders that have passed remediation deadlines), if applicable; and*
- A discussion of trends with respect to open work orders.

In addition, each electrical corporation must:

- *Graph open work orders over time as reported in the QDRs (Table 2, metrics 7.a and 7.b); and*
- *Provide an aging report for work orders past due*

Utility Initiative Tracking ID: VM-09

PG&E manages work resulting from VM inspections through the various programs in VM. Each of these programs are governed by the procedures listed below.

- The Distribution Routine Patrol Procedure (DRPP) (TD-7102P-01);
- Transmission Non-Orchard Routine Patrol Procedure (TRPP) (TD-7103P-01);
- Transmission Orchard Routine Patrol Procedure (TOPP) (TD-7103P-02) documents the work order process; and
- Vegetation Management Second Patrol Procedure (TD-7102P-23).

All trees identified during inspections as needing work trimming- or removal- by pre--inspectors are evaluated and prioritized based on potential risk to the system.

PG&E can be constrained by environmental delays, customer interference, permitting delays/restrictions or operational holds, weather conditions, active wildfire, and accessibility into the area where distribution system inspections are required. To address work backlog and constrained work in 2023, VM plans to start the process of centralizing constraints resolution.

<u>Open Work Order Trends</u>

As work is generated throughout the year through the inspection process, we typically see an increase of open work orders. The abundance of open work orders toward the end of the year is due to external constraints, invoicing, and in-progress work.

VM Tree Work Categorized by Age

Currently, there are time constraints in Second Patrol and on Priority Tag work. If an inspector determines that vegetation is an immediate risk to PG&E facilities the Priority Tag Utility Procedure is followed (TD-7102P-17).

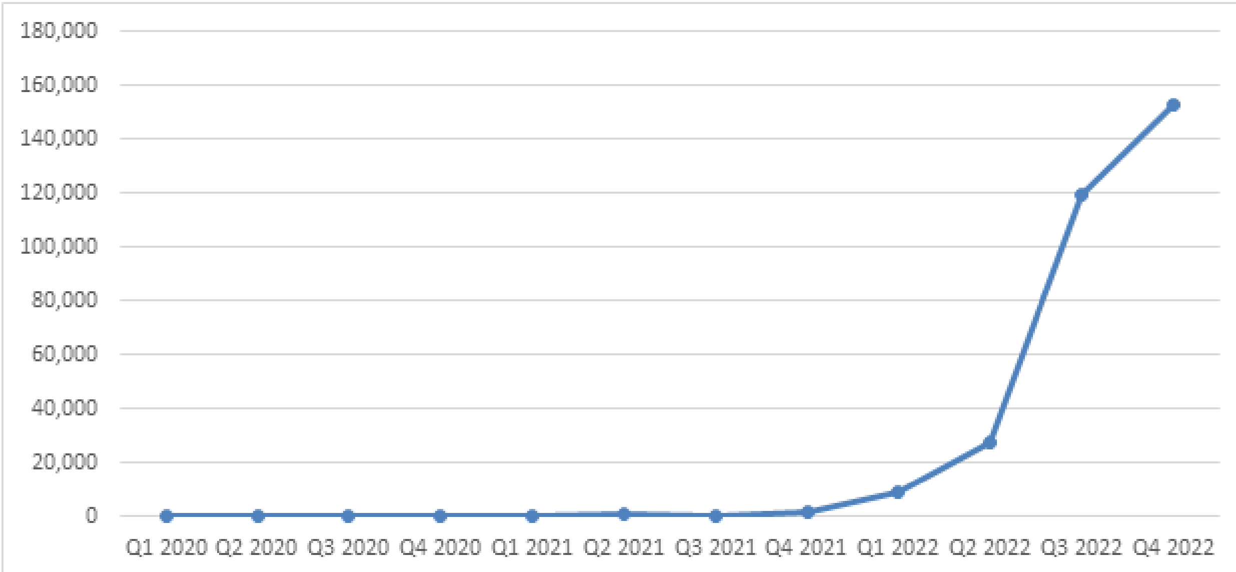
Under normal conditions, Priority 2 tags are issued for vegetation that is within MDR to the electric lines and must be mitigated within 20 business days. All other vegetation identified for follow-up work is scheduled for work following the standard process.

VM work orders often encompass multiple trees leading to varying timelines to complete all work within a single work order. Therefore, open work below is tracked at the tree level. Table 8-19 shows aging tree work including Priority Tags and Second Patrol excluding constrained trees. Data provided is as of February 28, 2023, and it is based on patrol records from November 15, 2019 forward. There are no Priority 1 Tags reflected in the data below.

TABLE 8-19:
PRIORITY 1/PRIORITY 2 AND SECOND PATROL TREES CATEGORIZED BY AGE

HFTD Area	0-30 Days	31-90 Days	91-180 Days	181+ Days
Non-HFTD	0	27	0	34
HFTD Tier 2	0	3	0	79
HFTD Tier 3	0	3	0	183

FIGURE PG&E-8.2.7:
OPEN WORK ORDERS OVER TIME



8.2.7 Workforce Planning

In this section, the electrical corporation must provide a brief overview of its recruiting practices for VM personnel. It must also provide its worker qualifications and training practices for workers in the following target roles:

- *Vegetation inspections; and*
- *VM projects.*

VM Contract Management engages with vendors to provide personnel to support VM Programs across our service territory. Prior to contracting with vendors, we ensure the vendor is qualified to perform the work and we validate the vendors' safety record.

The VM Department sources qualified talent for internal positions.

8.2.7.1 Workforce Planning – Vegetation Inspections

For each of the target roles listed above, the electrical corporation must:

- *List all worker titles relevant to the target role;*
- *List and explain minimum qualifications for each worker title with an emphasis on qualifications relevant to VM. Note if the job requirements include the following:*
  - Special certification requirements, such as being an *ISA* Certified Arborist with specialty certification as a Utility Specialist or CA-licensed Registered Professional Forester;
  - Additional *training on biological resources identification and protection (e.g., plant and animal species and habitats); and cultural prehistoric and historic resources identification and protection;*
- *Report the percentage of electrical corporation and contractor full-time equivalents (FTE) in target roles with specific job titles; and*
- *Report plans to improve qualifications of workers relevant to VM. The electrical corporation must explain how it is developing more robust outreach and onboarding training programs for new electric workers to identify hazards that could ignite wildfires.*

Table 8-20 provides an example of the required information.

Table 8-20, displayed below, lists our qualifications and training for VM Inspections and Management Projects.

TABLE 8-20:
VM INSPECTIONS AND MANAGEMENT PROJECTS – QUALIFICATIONS AND TRAINING

Worker Title	Min. Quals for Target Role[b],[c]	Special Certification Requirements	PG&E's % FTE Min. Quals	PG&E % Special Certifications[a]	Contractor % FTE Min. Quals	Contractor % Special Certifications[a]	Vegetation Inspection or Management
VMI	High School Diploma or General Educational Development (GED) AND Required to maintain a Class C driver's license AND must meet one of the experience levels below: One 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	N/A	49%		75%		Inspection
Senior VMI	High School Diploma or GED AND Required to maintain a Class C driver's license 5 years Tree Crew Climber/Crew Foreman with at least 2 years of line clearance certification OR 5 years of experience as a VMI and ISA Certified Arborist OR	N/A	51%		8%		Inspection

TABLE 8-20:
VM INSPECTIONS AND MANAGEMENT PROJECTS – QUALIFICATIONS AND TRAINING
(CONTINUED)

Worker Title	Min. Quals for Target Role[b],[c]	Special Certification Requirements	PG&E's % FTE Min. Quals	PG&E % Special Certifications[a]	Contractor % FTE Min. Quals	Contractor % Special Certifications[a]	Vegetation Inspection or Management
	5 years Registered Professional Forester (RPF) OR 5 years as a Utility Inspector or higher classification with at least 1 year of VM experience OR 4 years of Military Service with honorable discharge and at least 1 year of VM experience						
Estimating Arborist	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	N/A	N/A		1%		Inspection
Pre-Inspection Manager (PIM)	2 years Tree Crew Climber/Crew Foreman OR 2 years ISA Certified Arborist OR 2 years RPF	Certified Arborist or equal field experience qualification	N/A	N/A	16%	N/A	Management

(a) PG&E records employee special certifications only at the date of hire and does not track special certifications obtained by employees after onboarding. PG&E does not track contractor special certifications.

(b) The VMI roles do not require any of the three minimum qualifications (Qualified Electrical Worker (QEW), special certifications, advanced knowledge of GO 95). California Division of Occupational Safety and Health Title 8 regulations/Dept. of Industrial Relations defines an QEW as a qualified person who by reason of a minimum of two years of training and experience with high-voltage circuits and equipment and who has demonstrated by performance familiarity with the work to be performed and the hazards involved. Some VMIs are certified arborists, but it is not a requirement for these roles. PG&E uses the completion of VMI Basics training to ensure minimum qualifications are met before contractors can perform work in the field. Training requirements specific to the employee or contractor role are summarized below.

(c) Table PG&E-8.2.7-1 below lists the core PG&E VM courses. PG&E will update our basic VM course list in 2023. Until the course list is finalized, VM workers will be following the learning path in Table PG&E-8.2.7-1.

TABLE PG&E-8.2.7-1:
PG&E VMI BASIC WEB-BASED COURSES

Course Number	Course Name	Description
VEGM-0101WBT	Introduction to Pre-Inspection Basics	Electrical equipment basics, the VM patrol process, tree work, and customer relations.
VEGM-0102WBT	Mapping Patrol Line Segments	How to identify patrol line segments on the index map.
VEGM-0103WBT	Pre-Inspection Tools and Practices	Tools and procedures PIs must follow during VM work activities.
VEGM-0105WBT	Tree Strike Potential	Strike potential decision process and data entry into the mobile device.
VEGM-0106WBT	Major Woody Stem Exemption	Major woody stem exemption decision process.
VEGM-0107WBT	Tree Growth Potential	Tree growth potential decision process and data entry into the mobile device.
VEGM-0108WBT	Abnormal Filed Conditions Reporting	Identify abnormal field conditions during VM work activities
VEGM-0109WBT	Assess Treatment of Resprouting Stumps	How to identify and treat resprouting stumps.
VEGM-0110WBT	Skills Assessment for VMIs	Final skill assessment that will test key subjects from past VM training.

ISA Certification is currently not a requirement for VMIs. For a VMI to become certified, they require a certain level of experience and on-the-job training. PG&E has developed Tree Crew and Inspector Training programs to develop a steady pipeline of qualified personnel who may later join our contract or internal VM workforce. PG&E's PI basics training path and related training courses provide personnel with an opportunity to earn continuing education credit that can be used towards obtaining certification. Our educational partnerships allow us to provide employees and contractors with a direct path of obtaining certification

To bolster recruitment and the pipeline of qualified personnel, we have partnered with the International Brotherhood of Electrical Workers and educational institutions, such as the California Community College system, to establish a training program designed to provide the skills and knowledge necessary to perform tree crew work safely and competently.

The Tree Crew training curriculum was initially developed by Butte College and industry leaders and now the curriculum is being taught throughout California to introduce more people to the industry.

More than 350 people have successfully completed the Tree Crew Training Program. These individuals are now more likely to both enter the industry and be available as a qualified tree worker for PG&E. The colleges teaching the PI Training curriculum includes:

- 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 College.

8.2.7.2 Workforce Planning – VM Projects

In this section, the electrical corporation must provide a brief overview of its recruiting practices for VM personnel. It must also provide its worker qualifications and training practices for workers in the following target roles:

- *Vegetation inspections; and*
- *VM projects*

For each of the target roles listed above, the electrical corporation must:

- *List all worker titles relevant to the target role;*
- *List and explain minimum qualifications for each worker title with an emphasis on qualifications relevant to VM. Note, if the job requirements include the following:*
  - Special certification requirements, such as being an *ISA* Certified Arborist with specialty certification as a Utility Specialist or a CA-licensed Registered Professional Forester;
  - *Additional training on biological resources identification and protection (e.g., plant and animal* species *and habitats); and cultural prehistoric and historic resources identification and protection;*
- *Report the percentage of electrical corporation and contractor FTEs in target roles with specific job titles; and*
- *Report plans to improve qualifications of workers relevant to VM. The electrical corporation must explain how it is developing more robust outreach and onboarding training programs for new electric workers to identify hazards that could ignite wildfires.*

Workforce information for VM personnel is provided in Table 8-20 above.

PG&E describes our plans to improve qualifications of workers relevant to VM in Section 8.2.7.1 above.

8.3 Situational Awareness and Forecasting

8.3.1 Overview

In this section, the electrical corporation must identify objectives for the next 3- and 10-year periods, targets, and performance metrics related to the following situational awareness and forecasting programmatic areas:

- *Environmental monitoring systems;*
- *Grid monitoring systems;*
- *Ignition detection systems;*
- *Weather forecasting;*
- *Ignition likelihood calculation; and*
- *Ignition consequence calculation.*

8.3.1.1 Objectives

Each electrical corporation must summarize the objectives for its 3-year and 10-year plans for implementing and improving its situational awareness and forecasting.[141] *These summaries must include the following:*

- *Identification of which initiative(s) in the Wildfire Mitigation Plan (WMP) the electrical corporation is implementing to achieve the stated objective, including Utility Initiative Tracking IDs;*
- *Reference(s) to applicable codes, standards, and best practices/guidelines and an indication of whether the electrical corporation exceeds an applicable code, standard, or regulation;*
- *Method of verifying achievement of each objective;*
- *A completion date for when the electrical corporation will achieve the objective; and*
- *Reference(s) to the WMP section(s) or appendix, including page numbers, where the details of the objective(s) are documented and substantiated.*

This information must be provided in Table 8-21 for the 3-year plan and Table 8-22 for the 10-year plan. Examples of the minimum acceptable level of information are provided in Tables below:

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141 Annual information included in this section must align with the Quarterly Data Report (QDR) data.

- Table 8-21 and Table 8-22 Information Summary: In Table 8-21 and Table 8-22, we are providing the objective name (Objective Name), a description of the objective (Objective Description), the anticipated outlook of the objective (3-Year/10-Year Outlook), the planned due date for the objective (Completion Date), the applicable Initiative Tracking ID(Initiative Tracking ID), "Applicable Regulations, Codes, Standards, and Best Practices", "method of verification", and "section and page #" references. As noted in Section 7.2.1, "Applicable Regulations, Codes, Standards, and Best Practices," "method of verification," and "section and page #" columns are not a part of the objective. Instead, the controlling objective information is in the "Objective Description" and "Completion Date" columns.

- Reporting: Unless changed through Energy Safety's Change Order process, PG&E will use the objectives in Table 8-21 and Table 8-22 below for quarterly compliance reporting including the QDR, Quarterly Notification (QN), and the Annual Report on Compliance (ARC). We note that throughout this 2023-2025 WMP, we discuss current plans for wildfire-related activities beyond the objectives in Table 8-21 and Table 8-22 . The timing and scope of these additional activities and work may change. We will not be reporting on these plans or activities in our QDR, QN, or ARC because they are not objectives but are descriptions of plans and activities in our 2023-2025 WMP to provide a complete picture of our wildfire mitigation activities.

- External Factors: All objectives in the below Table 8-21 and Table 8-22 are subject to External Factors which represent reasonable circumstances which may impact execution against objectives including, but not limited to, physical conditions, landholder refusals, environmental delays, 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 ID: We are including Initiative Tracking IDs in each section that has associated targets and objectives. Table 8-21 and Table 8-22 display the Tracking IDs we are implementing to tie the objectives to the narratives and initiatives in the WMP. The Initiative Tracking IDs will also be used for reporting in the QDR.

TABLE 8-21:
SITUATIONAL AWARENESS INITIATIVE OBJECTIVES (3-YEAR PLAN)

Objective Name	Objective Description	Applicable Initiative(s), Tracking ID(s)	Applicable Regulations, Codes, Standards, and Best Practices (See Note)	Method of Verification (i.e., Program)	Completion Date	Reference (Section and Page #)
Artificial Intelligence (AI) in Wildfire Cameras	Enable AI processing of Wildfire Camera Data to provide automated wildfire notifications in the internal PG&E monitoring tool (Wildfire Incident Viewer (WIV)).	SA-01	Early detection of new ignitions can help reduce the overall impact of the ignition through increased awareness and more rapid response.	Report from vendor outlining the deployment of the AI solution and incorporation of PG&E data feeds. Successful user testing for notification push to WIV.	6/30/2023	Section 8.3.2.3 Page 583
EFD and DFA Reporting	Develop scalable processes to: (a) analyze alarms and alerts from Early Fault Detection (EFD) and Distribution Fault Anticipation (DFA) sensors; (b) conduct field investigation and reporting; (c) track identified mitigations to completion; and (d) track effectiveness of issue identification and remediation using EFD/DFA technologies.	SA-03	EFD and DFA are emerging technologies. Standards and best practices are to be developed as PG&E gains expertise operating these technologies	a) Specification document – Analysis Methodology for identified EFD/DFA Use Cases b) Procedures detailing field processes for EFD/DFA field investigations c) Report for EFD/DFA Investigation Results and Remediations	12/31/2023	Section 8.3.3.3 Page 590
FPI and IPW Modeling – Revision Evaluation	Evaluate enhancements to the FPI (Fire Potential Index) model and the IPW (Ignition Probability Weather) model. This involves testing new features and types of model configurations that could improve model skill. At present we do not know if model skills can be improved, but we will attempt to do so.	SA-04	Industry best practice across California (CA) utilities is to run and improve their own FPI.	Documentation that demonstrates evaluation of enhancements to the FPI model.	12/31/2023	Section 8.3.6.3 Page 620
Evaluate FPI and IPW Modeling enhancements in 2023 - 2025	Evaluate enhancements to the FPI (Fire Potential Index) model and the IPW (Ignition Probability Weather) model in the 2023-2025 period. This work involves testing new features and types of model configurations that could improve model forecasting ability. For example, one of the features that will be evaluated for inclusion in the IPW model is the use of covered conductor on the system.	SA-05	Industry best practice across California (CA) utilities is to run and improve their own FPI.	Documentation that demonstrates evaluation of enhancements to the FPI model.	12/31/2025	Section 8.3.6.3 Page 620

TABLE 8-22:
SITUATIONAL AWARENESS INITIATIVE OBJECTIVES (10-YEAR PLAN)

Objective Name	Objective Description	Applicable Initiative(s), Tracking ID(s)	Applicable Regulations, Codes, Standards, and Best Practices (See Note)	Method of Verification (i.e., Program)	Completion Date	Reference (Section and Page #)
Evaluate FPI and IPW Modeling enhancements in 2026 - 2032	Evaluate enhancements to the FPI (Fire Potential Index) model and the IPW (Ignition Probability Weather) model in the 2026-2033 period. This work involves testing new features and types of model configurations that could improve model forecasting ability.	SA-06	Industry best practice across California (CA) utilities is to run and improve their own FPI.	Documentation that demonstrates evaluation of enhancements to the FPI model.	12/31/2032	Section 8.3.6.3 Page 620

8.3.1.2 Targets

Initiative targets are forward-looking quantifiable measurements of activities identified by each electrical corporation in its WMP. Electrical corporations will show progress toward completing targets in subsequent reports, including QDRs and WMP Updates.

The electrical corporation must list all targets it will use to track progress on its situational awareness and forecasting for the three years of the Base WMP. Energy Safety's Compliance Assurance Division and third parties must be able to track and audit each target.[142] *For each initiative target, the electrical corporation must provide the following:*

- *Utility Initiative Tracking IDs;*
- *Projected targets for each of the three years of the Base WMP and relevant units;*
- *The expected "x% risk impact" for each of the three years of the Base WMP. The expected x% risk impact is the expected percentage risk reduction per year, as described in Section 7.2.2.2; and*
- *Method of verifying target completion.*

The electrical corporation's targets must provide enough detail to effectively inform efforts to improve the performance (i.e., reduction in ignition probability or wildfire consequence) of the electrical corporation's situational awareness and forecasting initiatives.

Table 8-23 provides a list of current Situational Awareness Initiative Targets by Year.

- Table 8-23 Information Summary: In Table 8-23, we are providing the target name (Target Name), the applicable Initiative Tracking ID (Initiative Tracking ID) and a description of the Target for each applicable year (2023 Target & Unit, 2024 Target & Unit, 2025 Target & Unit), the "% Risk Impact" for each respective year, and the method of verification. As noted in Section 7.2.1, the % Risk Impact and method of verification columns are not a part of the Target. Instead, the controlling target information is in the "Target & Unit" columns for each respective year
- Utility Initiative Tracking ID: We are including Initiative Tracking IDs in each section that has associated targets and objectives. Table 8-23 displays the Tracking IDs we are implementing to tie the targets to the narratives and initiatives in the WMP. The Initiative Tracking IDs will also be used for reporting in the QDR.
- Reporting: Unless changed through Energy Safety's Change Order process, PG&E will use the Targets in Table 8-23 below for quarterly compliance reporting including the QDR, QN, and the ARC. It is also important to note that throughout this

142 *Annual information included in this section must align with Table 1 of the QDR.*

2023-2025 WMP, we discuss current plans for wildfire-related activities in addition to the Targets in Table 8-23. The timing and scope of these additional activities and work may change. We will not be reporting on these plans or activities in our QDR, QN, or ARC because they are not Targets but are descriptions of plans and activities in our 2023-2025 WMP to provide a complete picture of our mitigation activities.

- % Risk Impact: The % Risk Impact provided in Table 8-23 is calculated based on the risk reduction of the mitigation initiative divided by total overall utility risk as defined in Section 6.4.2, Section 7.2.2.2, and Section 7.2.2.3. The % Risk Impact provided is an estimate based on the best available workplans applied against the latest risk models as of time of this filing. Please note, 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, for inspection and line sensor related targets, since inspections in of themselves do not reduce risk, instead we provided an “Eyes-on-Risk” value to provide insights into the level of risk being assessed.

- External Factors: All targets in the below Table 8-23 are subject to External Factors which represent reasonable circumstances which may impact execution against targets including, but not limited to, physical conditions, landholder refusals, environmental delays, 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.

- High Fire Threat District (HFTD), High Fire Risk Area (HFRA), Buffer Areas: Unless stated otherwise, all initiative work described in Table 8-23 involves work or audits on units or equipment located in, traversing, energizing, or protecting units or equipment in HFTD, HFRA, or Buffer Zone areas.

TABLE 8-23:
SITUATIONAL AWARENESS INITIATIVE TARGETS BY YEAR

Target Name	Initiative Activity Tracking ID	Reference Section	2023 Target & Unit	x% Risk Impact 2023	2024 Target & Unit	x% Risk Impact 2024	2025 Target & Unit	x% Risk Impact 2025	Method of Verification
Line Sensor – Installations	SA-02	8.3.3.1	Install Line Sensor devices on 40 circuits.	8% (Eyes-on-Risk)	Install Line Sensor devices on 40 circuits.	TBD	Install Line Sensor devices on 40 circuits.	TBD	Completed job packages

8.3.1.3 Performance Metrics Identified by the Electrical Corporation

Performance metrics indicate the extent to which an electrical corporation's WMP is driving performance outcomes. Each electrical corporation must:

- *List the performance metrics the electrical corporation uses to evaluate the effectiveness of its situational awareness and forecasting in reducing wildfire and Public Safety Power Shutoff (PSPS) risk.*[143]

For each of these performance metrics listed, the electrical corporation must:

- *Report the electrical corporation's performance since 2020 (if previously collected);*
- *Projected performance for 2023-2025; and*
- *List method of verification.*

The electrical corporation must ensure that each metric's name and values are the same in its WMP reporting as its QDR reporting (specifically, QDR Table 2 and QDR Table 3). Metrics listed in this section that are the same as performance metrics required by Energy Safety and reported in QDR Table 2 (Performance Metrics)[144] *must match those reported in QDR Table 2.Metrics listed in this section that are not the same as any of the performance metrics identified by Energy Safety and reported in QDR Table 2 must match those reported in QDR Table 3.*

The electrical corporation must:

- *Summarize its self-identified performance metric(s) in tabular form; and*
- *Provide a brief narrative that explains trends in the metrics.*

Table 8-24 lists Situational Awareness and Forecasting performance metrics results by year.

PG&E tracks the number of distribution outages while EPSS is enabled. Recognizing that there is year-to-year variability in outage activity, we are taking steps to reduce the number of outages that occur while EPSS is enabled. PG&E launched EPSS as a pilot project in 2021 and in 2022 expanded the scope of EPSS to all HFRAs and select adjacent EPSS buffer zones. We are projecting a decrease in the number of events by approximately 2 percent each year from 2023-2025 compared to the number of events in 2022.

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143 There may be overlap between the performance metrics the electrical corporation uses and performance metrics required by Energy Safety. The electrical corporation must list these overlapping metrics in this section in addition to any unique performance metrics it uses.

144 The performance metrics identified by Energy Safety are included in Energy Safety's Data Guidelines.

Performance metrics related to frequency, scope, and duration of PSPS events are largely weather dependent and customer impact will fluctuate depending on the meteorological conditions and grid configuration at the time of each event.

Using our 2023 workplans for undergrounding and MSO replacements, PG&E projected PSPS metrics into 2023 and keeps those values static for 2024-2025. PG&E anticipates continued improvement from 2023-2025, but we do not yet have final workplans and analysis on the value of those improvements for the following years.

TABLE 8-24:
SITUATIONAL AWARENESS AND FORECASTING PERFORMANCE METRICS RESULTS BY YEAR

Performance Metrics	2020	2021	2022	2023 Projected	2024 Projected	2025 Projected	Method of Verification (e.g., third-party evaluation, QDR)
Number of EPSS Events	(a)	(a)	2,375	2,350	2,300	2,250	QDR(b)
Duration of PSPS Events (in customer hours)	22.3M	2.5M	0	12.3M	12.2M	12.0M	QDR(c)
Total Number of Customers Impacted by PSPS	649,685	80,319	0	317,151	313,527	309,138	QDR(d)

(a) No data available as PG&E's EPSS program started only from 2022.
(b) QDR Table 10, QDR No. 1d.
(c) QDR Table 10, QDR No. 1c.
(d) QDR Table 10, QDR No. 4a.

8.3.2 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.*

Reference the Utility Initiative Tracking ID where appropriate

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In this section, we describe 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.

8.3.2.1 Existing Systems, Technologies, and Procedures

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. At a minimum, the electrical corporation must discuss systems, technologies, and procedures related to the reporting of the following:

- *Current weather conditions:*
  - *Air temperature;*
  - *Relative humidity; and*
  - Wind *velocity (speed and direction).*
- *Fuel characteristics:*
  - *Seasonal trends in fuel moisture.*

Each system must be summarized in Table 8-25. 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., HFTD, 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 8-25:
ENVIRONMENTAL MONITORING SYSTEMS

System	Measurement/ Observation	Frequency	Purpose and Integration
Weather Stations	• Sustained Steady wind speed velocity • Wind Gust Speed Gust wind velocity • Air temperature • Relative humidity	Standard 6 observations/hour 120 observations per hour can be enabled on most stations	• Situational awareness • Improve weather forecasts through data assimilation by Meteorological Assimilation Data Ingest System (MADIS) • Validate weather models performance
Fuel Moisture Sampling and Modeling	Percentage of moisture in Collect samples of specific plant species from 30 select HFTD locations across the territory	Once a month	• To validate fuel moisture models • Improve Situational awareness • Build robust historical fuel moisture datasets

Weather Stations

Summary: There is high wildfire risk across many remote areas within PG&E's 70,000-square-mile 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 in Diablo 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 (RAWS) and National Weather Service (NWS) Weather Stations in remote areas of California, there are many locations where micro-scale 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. These stations are directly used during PSPS events.

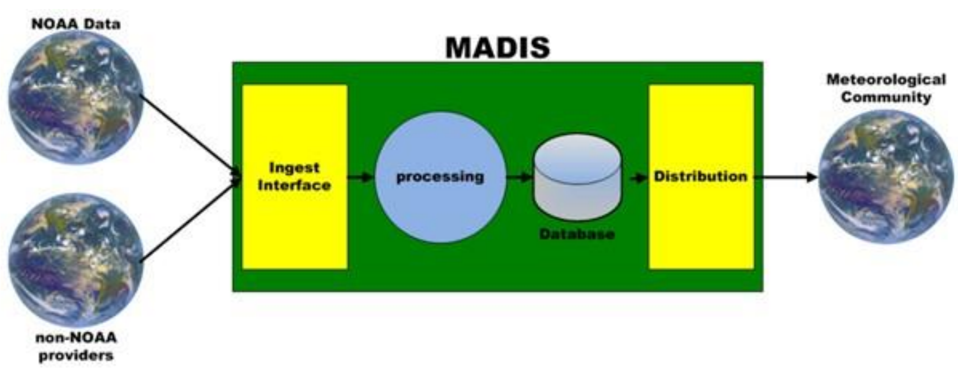
A primary benefit of data collected from our weather stations is the enhanced visibility into real-time weather-related risk. Our weather stations provide more spatial and temporal granularity into conditions than the state and federal weather station networks. For example, federal Remote Automated Weather Stations provide a weather reading once per hour, while PG&E's weather stations provide a reading at least every 10 minutes with an option to enable observations every 30 seconds. Due to the extreme topography of California and the vast number of micro-climate and local effects, our weather station network provides necessary coverage in remote areas

We use our weather stations year-round to monitor temperatures, wind speeds, wind gusts and relative humidity, and they are crucial during PSPS events. Readings from stations are evaluated in real-time in the Emergency Operations Center to inform the PSPS decision-making process and to validate conditions before the weather all-clear is declared. We also use these stations to verify our 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. For example, 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 in turn are used by PG&E to run our high-resolution weather models. Thus, increasing the coverage of observations in California should lead to incremental improvements in NCAR's forecast ability. Figure PG&E-8.3.2-1 below provides a high-level schematic of the MADIS platform.

FIGURE PG&E-8.3.2-1:
MADIS SCHEMATIC



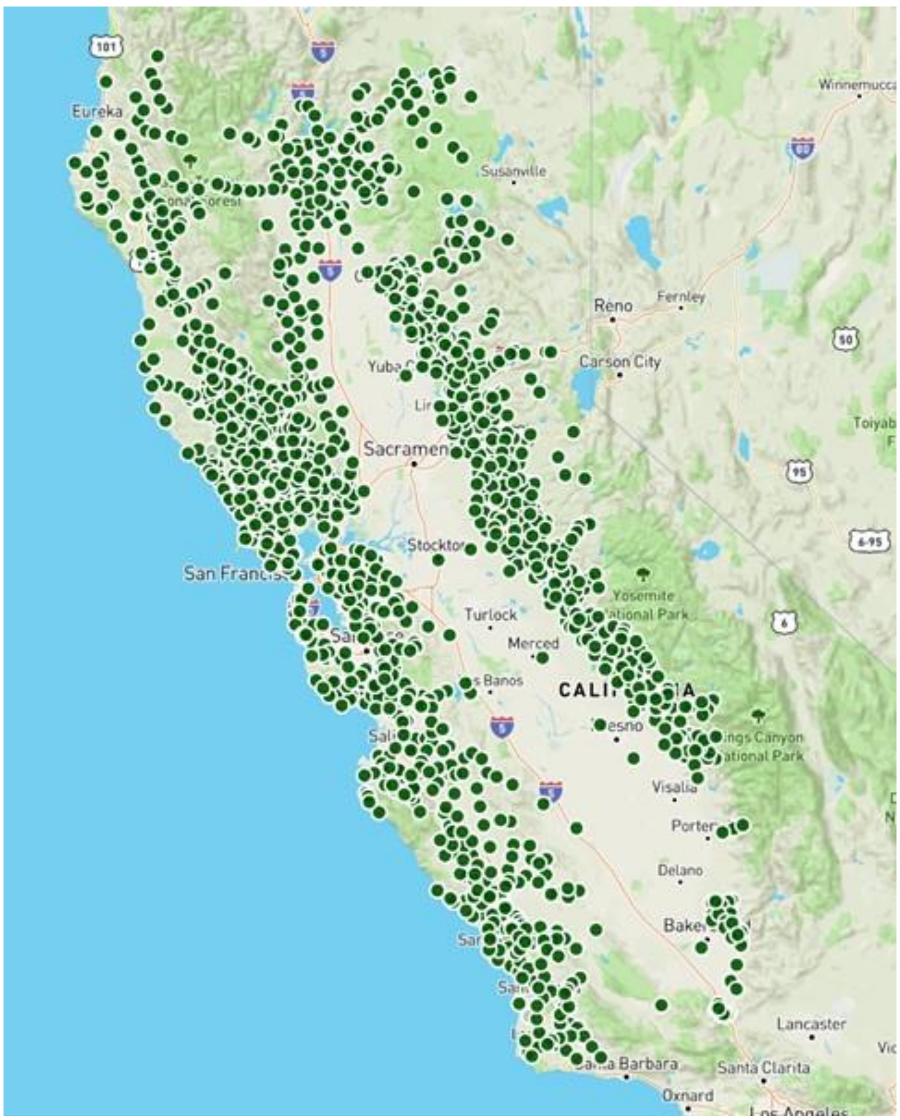
Source: https://madis.ncep.noaa.gov/#:~:text=MADIS%20is%20a%20meteorological%20observational,observational%20units%20and%20time%20stamps.

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 high fire risk areas of our service territory. The station coverage as of December 1, 2022, is shown in PG&E-8.3.2-2 below.

The figure shows that there is much less weather station coverage in the Central Valley because it is a non-HFTD area. This map below only shows PG&E-installed weather stations. There are hundreds of additional weather stations such as NWS and Remote Automated Weather Stations not shown on the map that we leverage.

FIGURE PG&E-8.3.2-2:
PG&E'S WEATHER STATION COVERAGE AS OF DECEMBER 1, 2022



Note: Source: https://explore.synopticdata.com/metadata/map/3765,-11768,6?network=229.

Integration With the Broader Utility System

Our weather station data is made available to the public through MADIS and is also ingested in real-time using Application Programming Interfaces (API). The data are stored in redundant databases internally and externally. Station data is integrated into real-time tools such as our weather all-clear dashboards.

Process to Verify Measurements from the System and Frequency of Maintenance

Each weather station instrument is calibrated in the factory 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 of each station, the vendor performs automated checks on weather station data (e.g., range and reasonableness checks) and sends us 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 any 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).

Frequency of Maintenance

We attempt to perform a site calibration including maintenance of each weather station at least once per calendar year. Site calibration is done by both by external and internal resources who follow our standard. 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 station data regularly reports data every 10 minutes. Weather stations are mechanical devices and can sometimes fail. Some of our stations have also been subject to vandalism from gunshots.

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)

Fuel Characteristics: Seasonal Trends in Fuel Moisture

Summary: Measuring moisture content throughout the year in living and dead vegetation is a critical component of our environmental monitoring systems that help build our 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 outputs of the models are used in the FPI Model, 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 30 designated PG&E fuel sampling sites.

Generalized Location of the System/Locations Measured by the System (e.g., HTFD, Entire Service Territory)

Each site is an HFTD. Collectively, these sites cover the entire PG&E territory from Humboldt to the Tehachapi.

Integration With the Broader Utility System

Each month we compile an LFM report to aid our situational awareness. A sample from December 2022 is presented below (Figure PG&E-8.3.2-3). 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 (Figure PG&E-8.3.2-4).

FIGURE PG&E-8.3.2-3:
DECEMBER 2022 SAMPLE LFM REPORT

Chamise

Site Number and Name	Elevation	Date	% Moisture	Trend
				↗ ↘ →
North Coast				
#11 Old Toll Rd	1200'	11/8/2022	61	↘
#12 Poonkinney Ridge	2760'	10/31/2022	67	→
#13 Walker Ridge	2200'	11/16/2022	62	→
#14 Kelseyville	2400'	11/16/2022	68	→
#15 Pine Flat	3200'	11/1/2022	59	→
#16 Lower Cow Mountain	1120'	11/3/2022	74	→
North Valley				
#26 Fouts Springs	1410'	11/15/2022	67	↘
Central				
#42 Vallecito	2000'	11/4/2022	68	→
#43 Priest Grade	2500'	11/4/2022	66	↘
Bay Area				
#51 Las Trampas	1300'	11/4/2022	66	→
#53 Bonny Doon	1600'	10/31/2022	79	↘
South Coast				
#61 Templeton	1200'	11/22/2022	62	↘
#62 Pozo	2100'	11/22/2022	62	→
#64 Happy Canyon	1270'	11/16/2022	61	↗
		Chamise Average	66	↘

Manzanita

Site Number and Name	Elevation	Date	% Moisture	Trend
				↗ ↘ →
North Coast				
#16 Lower Cow Mountain	1120'	11//3/2022	78	↘
#17 Alderpoint	960'	11/16/2022	134	↗
#18 Friday Ridge	700'	11/15/2022	95	↗
#19 Loch Haven	1100'	11/3/2022	77	→
North Valley				
#21 Shasta Dam	1430'	10/31/2022	71	↘
#22 Shingletown	2000'	11/14/2022	104	↗
#23 Oak Run	1930'	10/31/2022	65	→
#24 De Sabla	2640'	11/14/2022	89	↘
#25 Oregon House	1850'	11/14/2022	93	↗
Sierra				
#31 Sweetland	2000'	11/16/2022	110	↗
#32 Bowman	1400'	11/16/2022	104	↗
#33 Rollins Reservoir	2660'	11/1/2022	99	↘
#34 Dutch Flat	3100'	11/16/2022	100	↗
#35 Pollock Pines	3080'	10/31/2022	102	↘
#36 Cameron	1450'	10/31/2022	70	→
Central				
#41 Pine Acres	2700'	11/4/2022	82	↗
South Valley				
#71 Oakhurst	4000'	11/4/2022	78	↗
#72 Tollhouse	3400'	11/4/2022	74	↗
#73 Frazier Park	4700'	11/16/2022	77	↗
#74 Dunlap	4380'	11/14/2022	58	↘
		Manzanita Average	88	↗
Total Samples Collected			109	

PG&E Site Number and Plant Type

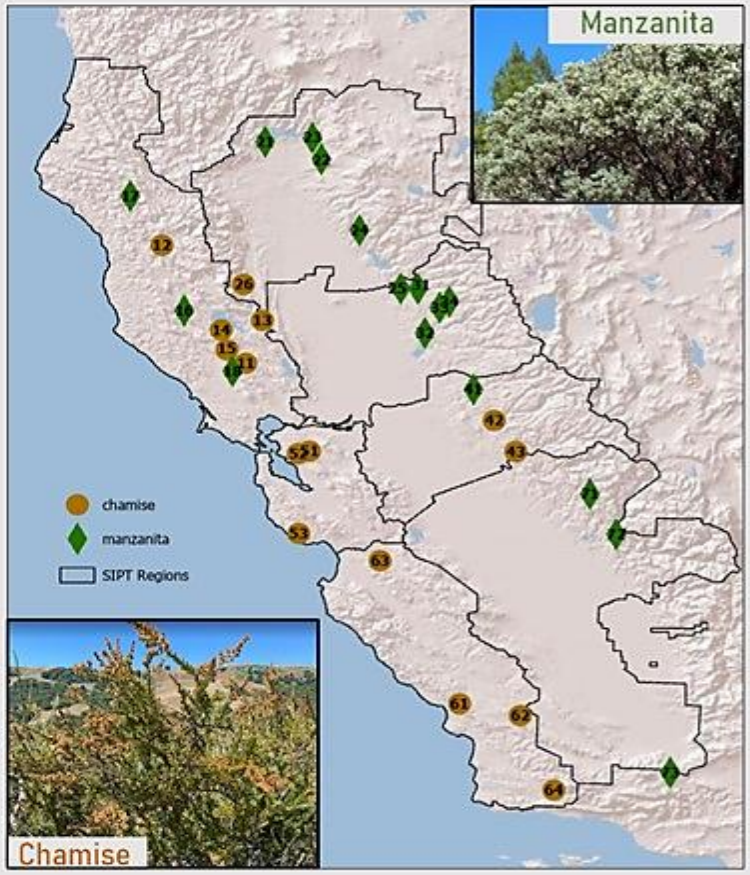
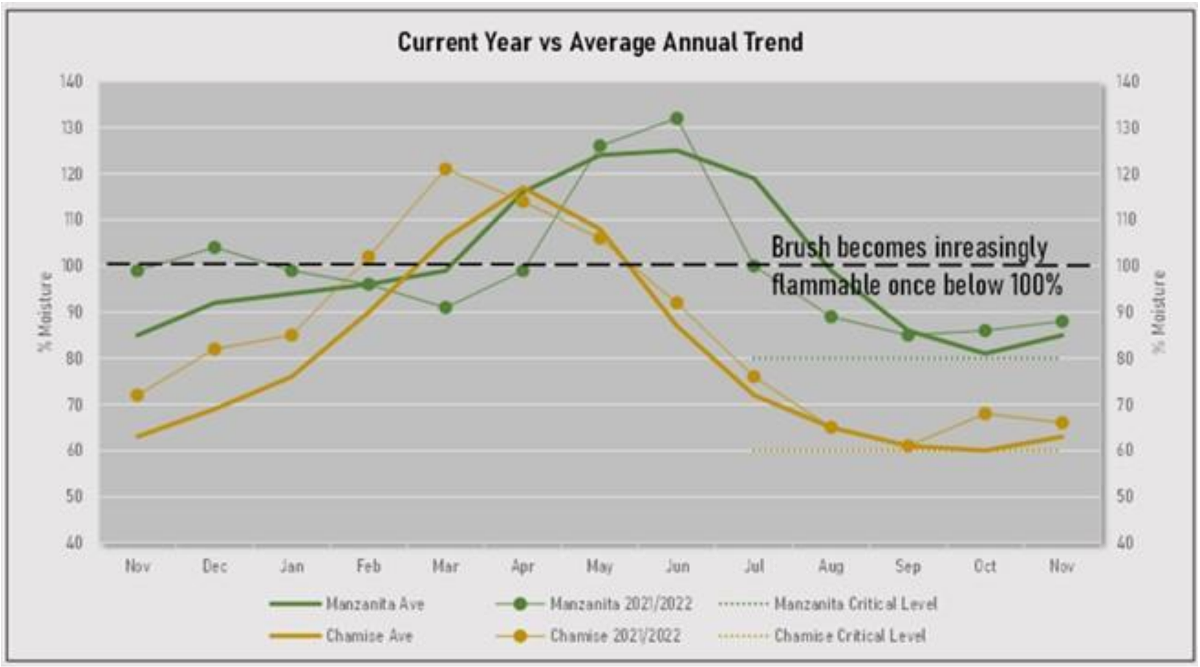


FIGURE PG&E-8.3.2-4:
SAMPLE LFM SEASONAL TRENDS



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 and building a historical dataset. The National Fuel Moisture Database is publicly available through the National Forest Service's Wildfire Assessment System website.

Frequency of Maintenance

This process is relatively maintenance-free apart from basic lab equipment and field tools that are used to perform and process the sample.

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.

Regularly scheduled site visits are conducted once per month.

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:

$$\frac{(weight\ of\ water\ in\ sample)}{(dry\ weight\ of\ sample)}\ (100) = \text{percent of moisture content}$$

Use this formula for a simpler method:

$$\frac{(wet\ weight\ of\ sample - dry\ weight\ of\ sample)}{(dry\ sample\ weight - container\ tare\ weight)}\ (100) = \text{percent of moisture content}$$

8.3.2.2 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 should 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).

We are not currently evaluating new environmental monitoring systems or networks. We use a variety of environmental monitoring systems including weather stations, cameras, and satellite data.

8.3.2.3 Planned Improvements

The electrical corporation must describe its planned improvements for its environmental monitoring systems. This must include any plans for the following:

- *Expansion of existing systems; and*
- *Establishment of new systems.*

For each planned improvement, the electrical corporation must provide the following in Table 8-26:

- *<u>Description</u>: A description of the planned initiative activity;*
- *<u>Impact</u>: Reference to and description of the impact of the initiative activity on each risk and risk component;*
- *<u>Prioritization</u>: A description of the x% risk impact (see <u>Section 8.1.1.2</u> for explanation); and*
- *<u>Schedule</u>: A description of the planned schedule for implementation.*

Utility Initiative Tracking ID: SA-01

**TABLE 8-26:
PLANNED IMPROVEMENTS TO ENVIRONMENTAL MONITORING SYSTEMS**

System	Description	Impact	X% Risk Impact	Implementation Schedule
Please see below for narrative description.	N/A	N/A	N/A	N/A

We are not currently evaluating new environmental monitoring systems or new networks.

Our LFM sampling program is in the steady-state phase, and we have no plans to expand the program beyond the initial scope.

Our weather station network is nearing full maturity with more than 1,400 weather stations installed. We will continue to evaluate the need for additional stations throughout our service territory.

8.3.2.4 Evaluating Mitigation Initiatives

The electrical corporation must describe its procedures for the ongoing evaluation of the efficacy of its environmental monitoring program

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Our meteorology team assesses the efficacy and accuracy of the data it receives by working with our weather station vendor, Western Weather Group. They perform automated error checking on data coming from each weather station. If an issue is found with data quality, a notification is sent to us, and a ticket is then issued to our internal or external teams to evaluate the station.

8.3.3 Grid Monitoring Systems

The electrical corporation must describe its systems, and procedures used to monitor the operational conditions of its equipment. 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.*

Reference the Utility Initiative Tracking ID where appropriate.

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.[145] 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.

8.3.3.1 Existing Systems, Technologies, and Procedures

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 8-27 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;*
- *Integration with the broader electrical corporation's system;*

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145 Please refer to Section 8.1.8.1.3.1 for a description of PG&E's activities related to the Rapid Earth Current Fault Limiter.

- *How measurements from the system are verified;*

- *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 to calculated quantities. This should include flow charts and equations as appropriate.*

Utility Initiative Tracking ID: SA-02

Table 8-27 below summarizes our grid operation monitoring systems.

**TABLE 8-27:
GRID OPERATION MONITORING SYSTEMS**

System	Measurement/Observation	Frequency	Purpose and Integration
Line Sensors	Current/Fault Current	15 minutes/triggered by fault magnitude threshold.	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.	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.	Detect failing equipment early, detect vegetation encroachment. Plan to integrate into analytics platform.
Reclosers	Current/Voltage/ Power/Fault Data	Continuously	Data is used to provide real-time fault information as well as to assist in diagnosing system problems during and after events occur.

Faults

Location of the System/Locations Measured by the System

PG&E has 861 Line Sensor locations on 189 circuits and one DFA sensor each on 74 circuits. PG&E plans to install Line Sensors on 120 additional circuits between 2023 and 2025. These new line sensors and other equipment will be predominantly located in Tier 2 and Tier 3 HFTD.[146]

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.

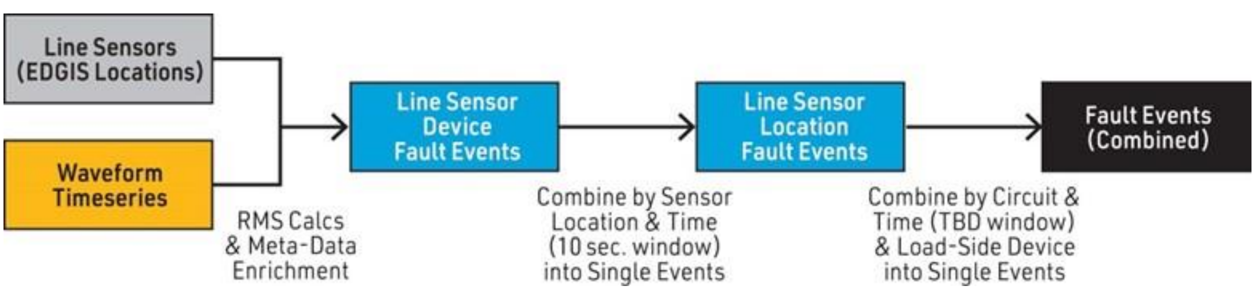
For Intermittent Systems (e.g., Aerial Imagery, Line Patrols), What Triggers Collection

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 are being integrated into Foundry so that the data can be analyzed and then we can calculate an approximate area of possible fault or disturbance based on the circuit model impedance within the power flow tool, made by CYME International. Using that approximate location and overlap of identified areas with logic generated based on protection operation we can define a narrow search. 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-8.3.3-1 below illustrates a fault events workflow.

FIGURE PG&E-8.3.3-1:
ILLUSTRATIVE FAULT EVENTS WORKFLOW



146 A list of locations is provided in Attachment 2023-03-27_PGE_2023_WMP _R0_Section 8.3.3_Atch01. Line Sensor and DFA data is as of end of year 2022.

Failures

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.

Location of the System/Locations Measured by the System

As of December 31, 2022, PG&E has deployed EFD sensors at 50 locations on 4 circuits. PG&E does not have a 2023 Target for EFD installations. We plan to develop and implement processes and procedures to analyze EFD alarms, conduct field investigations and track mitigation activities to effectively use EFD technology prior to deploying additional sensors.[147]

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

Integration with the PG&E system

Reclosers 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 LR s and SmartMeter™ outage alarms are currently used to capture LR operation.

Location of the System/Locations Measured by the System

Reclosers are placed throughout our grid network, along utility lines.

147 A list of locations is provided in Attachment 2023-03-27_PGE_2023_WMP _R0_Section 8.3.3_Atch01. EFD data is as of end of year 2022.

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 Faults section above applies to reclosers as well.

8.3.3.2 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 should include flow charts as appropriate.

PG&E evaluates the need for additional grid operation monitoring systems through a risk-informed, Subject Matter Expert (SME) assessment of potential monitoring systems that, if deployed, could further reduce 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 and selecting additional grid operation monitoring systems is as follows:

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.

8.3.3.3 Planned Improvements

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.*

For each planned improvement, the electrical corporation must provide the following in Table 8-28:

- *Description: A description of the planned initiative activity;*
- *Impact: Reference to and description of the impact of the initiative activity on each risk and risk component;*
- *Prioritization: A description of the x% risk impact (see Section 8.1.1.2 for explanation); and*
- *Schedule: A description of the planned schedule for implementation.*

Utility Initiative Tracking ID: SA-03

**TABLE 8-28:
PLANNING IMPROVEMENTS TO GRID OPERATION MONITORING SYSTEMS**

System	Description	Impact	x% Risk Impact	Implementation Schedule
Line Sensors[a]	Install Line Sensor devices on 40 circuits feeding into HFTD areas or HFRA locations.	Ignition Likelihood	N/A	2023-2025
DFA and EFD Reporting[b]	In 2023, PG&E plans to develop scalable processes to: (a) analyze alarms and alerts from EFD and DFA sensors; (b) conduct field investigation and reporting; (c) track identified mitigations to completion; and (d) track effectiveness of issue identification and remediation using EFD/DFA technologies.	Ignition Likelihood	N/A	2023

(a) Please see Target SA-02 for more details in Section 8.3.1.2.
(b) Please see Objective SA-03 for more details in Section 8.3.1.1.

8.3.3.4 Evaluating Mitigation Initiatives

The electrical corporation must describe its procedures for the ongoing evaluation of the efficacy of its grid operation monitoring program.

We track line sensor installations through 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 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. Results of field investigations and any follow-up remediations will be tracked and will allow us to assess the effectiveness of the sensor technology.

8.3.3.5 Enterprise System for Grid Monitoring

In this section, the electrical corporation must provide an overview of its enterprise system for grid monitoring. This overview must include discussion of:

- *Any database(s) used for storage*
- *Describe the electrical corporation's internal documentation of its database(s)*
- *Integration with systems in other lines of business (LOB)*
- *Describe any Quality Assurance (QA)/Quality Control (QC) or auditing of its system*
- *Describe internal processes for updating the enterprise system including database(s)*
- *Any changes to the initiative since the last WMP submission and a brief explanation as to why those changes were made. Include any planned improvements or updates to the initiative and the timeline for implementation*

Any Database(s) Used for Storage

Data from the monitoring systems is stored in several locations. Each of the sensor systems has its own proprietary application database. In instances where interfaces have been developed to other PG&E systems (such has PI Historian), some sensor data get stored in those systems. Interface development from sensor systems to PG&E's Foundry analytics platform is in progress. Upon completion, the Foundry platform will house selected sensor data as well.

Describe the Electrical Corporation's Internal Documentation of Its Database(s)

Our internal documentation includes a solution blueprint for Electric Distribution PI[148] (EDPI), internal procedures, DR Plan, BIA, maintenance plan, and work order process, which are maintained in SharePoint.

Line sensors, EFD, and DFA systems use proprietary databases. This documentation resides with the vendor.

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148 EDPI is part of the PI System made by AVEVA. The PI System is a market-leading data management platform for industrial operations.

Integration With Systems in Other LOB

Data from these systems will be integrated into other operational systems including Distribution Management System (DMS) and Advanced Distribution Management System.

PI, a data historian platform, is used to record operations data. EDPI is used as a method to connect our line sensors to DMS and Foundry.

Describe Any QA/QC or Auditing of Its System

For the three sensor systems (Line Sensors, DFA, and EFD) we check periodically if systems are live and correctly communicating. If the answer is no, we troubleshoot remotely first and then do field troubleshooting/device replacement. Formal QA/QC processes (like periodic field inspections) will be established prior to systems exiting pilot mode. For mature grid monitoring systems like reclosers, formal periodic field inspections are in place.

Describe Internal Processes for Updating the Enterprise System Including Database(s)

On-premise systems managed by PG&E follow established Information Technology change management processes. This includes functional testing of new features and regression testing of existing capabilities in test environments before implementing in production. Vendor managed systems follow their respective internal change management processes.

Any Changes to the Initiative Since the Last WMP Submission and a Brief Explanation as to Why Those Changes Were Made. Include Any Planned Improvements or Updates to the Initiative and the Timeline for Implementation.

There have been minimal fundamental changes. In the near term we are focused on operationalization of the technology. We are continuing to assess current state of circuit risk and implementation priorities.

8.3.4 Ignition Detection Systems

The electrical corporation must describe its systems, technologies, and procedures used to detect ignitions within its service territory and gauge their size and growth rates.

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; and*
- *Monitoring of mitigation improvements;*

Reference the Utility Initiative 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 Wildfire Cameras. We also outline our process for assessing new systems, expanding existing systems, and evaluating the efficacy of our ignition detection program.

8.3.4.1 Existing Ignition Detection Sensors and Systems

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*;
  - *High-definition video; and*
  - *Infrared cameras.*
- *Fire growth potential software.*

The electrical corporation must summarize each system in Table 8-29 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 8-29:
FIRE DETECTION SYSTEMS CURRENTLY DEPLOYED

Detection System	Capabilities	Companion Technologies	Contribution to Fire Detection and Confirmation
PG&E FDAS	Satellite detection and alerts from 6 satellites. Update cadence is every 5 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. Data are shared with the public here: https://pgefdp.lovelytics.info/pge_fire_app/.
Wildfire Cameras	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.

Early Fire Detection

Satellite Infrared Imagery, High-Definition Video, and Infrared Cameras

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.

PG&E uses data from six satellites in FDAS. The satellites are located in space.

Resiliency of Sensor Communication Pathways

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, Alert California) and maintained by them 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.

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. They have 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, PG&E worked with multiple vendors to discuss how we can use AI to help detect new fires and enhance situational awareness.

The FDAS data does not have a machine learning component, but it does use sophisticated algorithms to translate the raw satellite data into fire detections.

Role of Sensor Data in Risk Response

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 severity and rate of spread.

PG&E sponsored over 600 wildfire cameras on the Alert California network since 2019. Camera detections also provides valuable information about the presence of new fires and the spread of existing fires.

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.

It takes about 10 minutes to process the satellite data to be 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 uses no network-based sensors.

Fire Growth Potential Software

Summary

PG&E works with Technosylva to simulate fire spread and consequence impacts. These simulations are performed across climatological time horizons to assess the highest risk areas over both long-term and short-term forecasts (over the next five days). Outputs are used in PSPS assessments, long-term planning models, and real-time fire spread analysis to understand the impacts of the risk, and to better understand the consequence from fires had PSPS not been executed.

General Location of Detection Sensors

The Technosylva application integrates satellite fire detections, wildfire camera data, and the Integrated Reporting of Wildland-Fire Information (IRWIN) database. IRWIN is a consolidated database of new incidents reported by California Department of Forestry and Fire Protection (CAL FIRE) and other agencies. Once a potential incident appears in IRWIN, fire simulations are automatically performed based on the geospatial location.

Resiliency of Sensor Communication Pathways

This section does not apply to the Technosylva simulation software.

Integration of Sensor Data into Machine Learning or AI Software

PG&E shares satellite data with Technosylva who has developed an application called Wildfire Analyst Enterprise that develops outcomes based on available fuels, topography, weather, structures, and population data. This application is used by other California utilities and CAL FIRE. PG&E allows stakeholders in California using this application to access and visualize PG&E's fire detection data free of charge.

Role of Sensor Data in Risk Response

Technosylva simulation outputs are used as the source of spatially resolved fire severity data that is the primary input into the spatial wildfire consequence calculations. Each day, PG&E delivers our high-resolution 2 x 2 kilometers (km) weather and fuels model data sets to Technosylva and they perform more than 100 million fire spread simulations every three hours showing simulations out 3 days. These simulations provide fire spread outputs (e.g., potential number of acres burned, and population impacted) and can be visualized per overhead circuit in forecast mode to determine the highest risk circuits every three hours.

PG&E also has the ability through Wildfire Analyst Enterprise to simulate fires on-demand. This involves selecting a location on a map, the start time of ignition, and the simulation duration in hours. The Technosylva wildfire spread model uses the dynamic weather forecast of wind and fuel moisture to model how the wildfire might spread. This technology allows PG&E to forecast approximately 100 million virtual fires daily across our territory in forecast mode, simulate fires on demand as they start, simulate hypothetical fires based on PSPS damage and hazard reports, and simulate fires in past weather scenarios.

Finally, PG&E has also developed a Wildfire Consequence Model using the Technosylva fire simulations. This model, combined with wildfire ignition probability models described above, are used to calculate Multi Attribute Value Function-calibrated risk scores.

False Positives Filtering

Does not apply to the Technosylva simulation software.

Time Between Detection and Confirmation

Does not apply to the Technosylva simulation software.

Security Measures for Network-Based Sensors

Does not apply to the Technosylva simulation software.

8.3.4.2 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 interpret this section as referencing additional systems or networks as opposed to adding incremental sensors to existing systems (e.g., a new camera).

Our team is 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 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.

As an example, in 2021 we conducted a pilot program with a vendor related to AI detection on cameras. In 2022 we continued our assessment through the Electric Program Investment Charge 3.45, "Automated Fire Detection from Wildfire Alert Cameras," program. Through our assessment period we determined that AI detection on camera will improve our detection system and in 2023 we will select a vendor to install AI detection on our cameras.

Our evaluation of emerging technologies generally follows the process below:

1. Identify new technologies or systems;
2. SME and business review for reasonableness and feasibility;
3. Evaluate alignment to program goals and objectives;
4. Benchmarking, if applicable;
5. Determine source of funding and cost review;
6. Perform pilot study if needed to evaluate effectiveness at achieving program goals and objectives and testing assumptions;
7. Implement and deploy system; and
8. SME operational review of benefits.

8.3.4.3 Planned Integration of New Ignition Detection Technologies

The electrical corporation must provide an implementation schedule for new ignition detection and alarm system technologies. This must include 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.*

For each new technology system, the electrical corporation must provide the following in Table 8-30:

- *Description: A description of the technology's capabilities;*
- *Impact: A description of the impact the technology will have on each risk and risk component;*
- *Prioritization: A description of the x% risk impact (see Section 8.1.1.2 for explanation); and*
- *Schedule: A description of the planned schedule for implementation.*

TABLE 8-30:
EXAMPLE OF PLANNING IMPROVEMENTS TO FIRE DETECTION AND ALARM SYSTEMS

System	Description	Impact	x% Risk Impact	Implementation Schedule
HD Camera AI Fire Detection Capability	Enable AI processing of Wildfire Camera Data to provide automated wildfire notifications in the internal PG&E monitoring tool (Wildfire Incident Viewer).	Ignition Consequence Wildfire Consequence	N/A	6/30/2023

We are not currently evaluating adding new environmental monitoring systems or new networks to our existing operational capabilities. However, we are evaluating the use of Wildfire Camera with AI along with CAL FIRE, California Governor's Office of Emergency Services (Cal OES) and other agencies working with the same vendor.[149] Our sponsorship will enable all stakeholders to use the AI solution. PG&E is working with the partners of ALERT California (https://alertcalifornia.org), a public safety program based at the University of California, San Diego, who is creating the AI technology and ensuring it is updated.

[149] Please see Objective SA-01 for more details in Section 8.3.1.1.

8.3.4.4 Evaluating Mitigation Initiatives

The electrical corporation must describe its procedures for the ongoing evaluation of the efficacy of its fire detection systems.

PG&E SMEs determine if our monitoring programs are sufficient. SMEs include members of the Hazard Awareness and Warning Center (HAWC) team and our Meteorology organization.

The HAWC team collects wildfire data year-over-year to determine where improvements can be made. HAWC processes and procedures are updated annually post-fire season using lessons learned from the most recent events. Working with our functional areas and collaborating with external partners, the teams evaluate the most recent season's impacts and identify areas for improvement. External partners include, CAL FIRE, Cal OES, United States Forest Service, other fire agencies, and the University of California San Diego (who runs the wildfire camera program), among others.

8.3.4.5 Enterprise System for Ignition Detection

In this section, the electrical corporation must provide an overview of its enterprise system for ignition detection. This overview must include discussion of:

- *Any database(s) used for storage;*
- *Describe the electrical corporation's internal documentation of its database(s);*
- *Integration with systems in other LOB;*
- *Describe any QA/QC or auditing of its system;*
- *Describe internal processes for updating the enterprise system including database(s) ; and*
- *Any changes to the initiative since the last WMP submission and a brief explanation as to why those changes were made. Include any planned improvements or updates to the initiative and the timeline for implementation.*

Any Database(s) Used for Storage

Data from the FDAS is stored in Structured Query Language (SQL) Server databases.

Describe the Electrical Corporation's Internal Documentation of Its Database(s)

Documentation includes disaster recovery documentation, so that they can failover to the failover server(s) if needed, and internal documentation of dataflow.

Integration With Systems in Other LOB

FDAS is integrated into Technosylva's software platform and shared with anyone with access to this tool including CAL FIRE. Data is also made available on PG&E's website. FDAS data is also integrated in the HAWC's situational awareness dashboards and systems.

Describe Any QA/QC or Auditing of Its System

The system is used in an operational setting and if issues are identified the meteorology analytics team is notified and, if needed, the SSEC. Any changes to system databases follow the logical deployment cycle from lower development environments, to QA, and then production.

Describe Internal Processes for Updating the Enterprise System Including Database(s)

Changes to the database are first tested in a development environment, migrated to a QA computer environment, and then migrated to production environments.

Any Changes to the Initiative Since the Last WMP Submission and a Brief Explanation as to Why Those Changes Were Made. Include Any Planned Improvements or Updates to the Initiative and the Timeline for Implementation.

No changes have been made to FDAS since the last WMP. In the future we plan to migrate the system from on-premises SQL server instances into our AWS cloud environment and PostgreSQL databases.

8.3.5 Weather Forecasting

The electrical corporation must describe its systems and procedures used to forecast weather within its service territory. These forecasts should 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 at reducing risk are monitored.*

Reference the Utility Initiative Tracking ID where appropriate.

In this section we describe our weather forecasting systems, technologies, and associated procedures. These are used to forecast and evaluate weather associated risks and inform our PSPS decision-making. Existing forecast systems include Fuel Moisture Sampling and Modeling, and Weather Stations. We also discuss our process for assessing new systems, expanding existing systems, and evaluating our weather forecasting program.

8.3.5.1 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; and*
- *Ensemble forecasting with control forecast and perturbations.*
- *Model inputs including, for example:*
  - *Land cover/land use type; and*
  - *Local topography.*
- *Model outputs including, for example:*
  - *Air temperature;*
  - *Barometric pressure;*
  - *Relative humidity;*
  - *Wind* velocity (speed and direction);

- *Solar radiation; and*
- *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; and*
  - *Vertical resolution.*
- *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.

Data Assimilation From Environmental Monitoring Systems Within the Electrical Corporation Service Territory

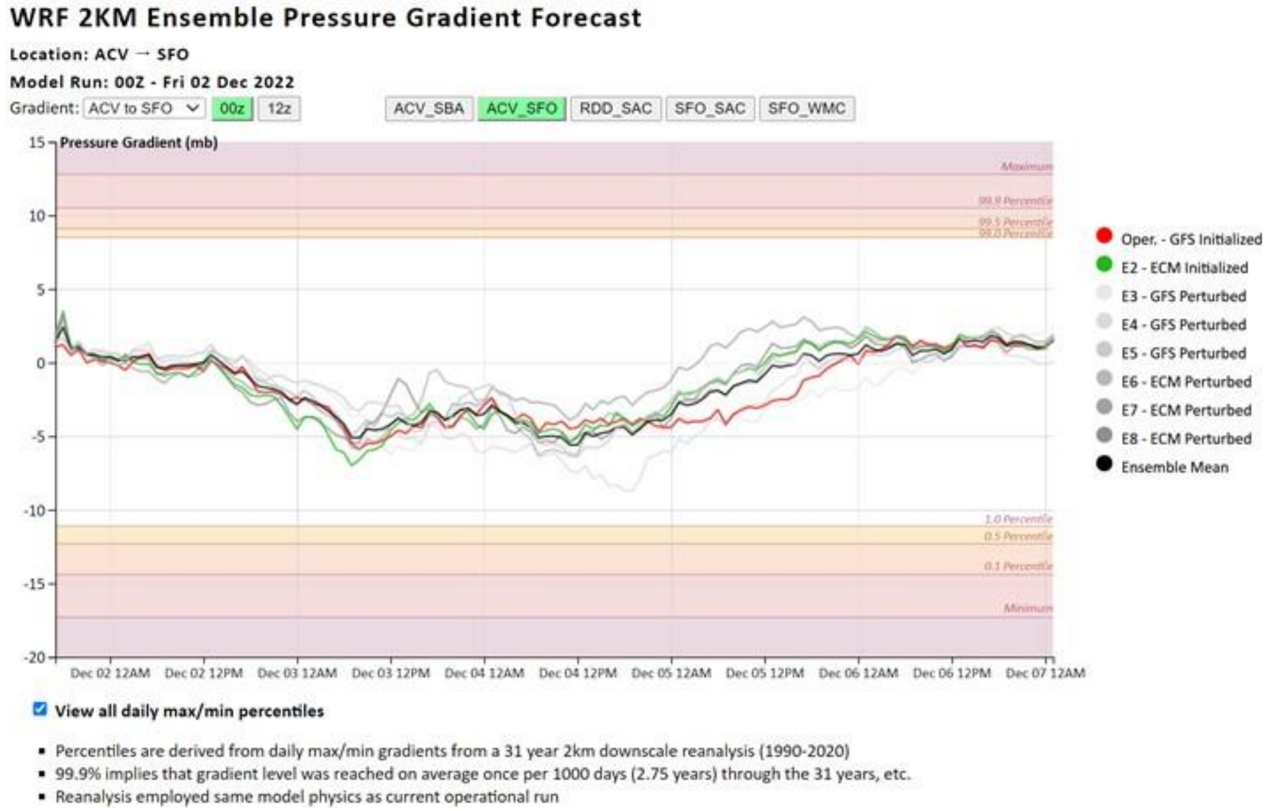
Data assimilation from monitoring systems is discussed in Section 8.3.2.1. The high-resolution weather forecasts are initialized using 1/4 Global Forecast System (GFS) forecast data and 1/12°Sea Surface Temperature analyses. Observational data available for assimilation is also taken from MADIS, and include conventional surface and upper-air observations, as well as aircraft data, and satellite-derived winds. Snow data from the North American Land Data Assimilation System is also assimilated.

Ensemble Forecasting With Control Forecast and Perturbations

There are eight forecast members in the current ensemble configuration. Four members (one control) are initialized with the National Center for Environmental Prediction GFS model, while the other four are initialized with the European Center for Medium-Range Weather Forecasts (ECMWF) Forecasting model. The control run is re-run four times per day on the 00z, 06z, 12z, 18z model cycles while the ensemble is run two times per day on the 00z and 12z model cycles.

Figure PG&E-8.3.5-1 below is one example visualization of each ensemble member for the forecast pressure gradient between Arcata and San Francisco, California. The shading represents the percentile distributions computed from a 30+ year model climatology created with the same model physics as the control run.

FIGURE PG&E-8.3.5-1:
WEATHER RANGE FORECAST, 2 KM RESOLUTION, OF ENSEMBLED PRESSURE GRADIENT FORECAST BETWEEN ARCATA (ACV) AND SAN FRANCISCO, CALIFORNIA (SFO), FOR 2 DEC. 2022



A high-resolution weather model ensemble is also initialized twice per day on the 00z and 12z forecast cycles. There are a total of eight forecast members of the ensemble. Four members are driven by the GFS global model, while four are driven by the European global model, ECMWF.

Figure PG&E-8.3.5-2 below is an example forecast pressure gradient forecast between Arcata, CA and San Francisco, CA for the 12z forecast initialized on Tuesday December 20, 2022. The output shows the forecasted gradient from each of the eight ensemble members and the ensemble mean.

FIGURE PG&E-8.3.5-2:
WEATHER RANGE FORECAST, 2 KM RESOLUTION, OF ENSEMBLED PRESSURE GRADIENT FORECAST BETWEEN ARCATA (ACV) AND SAN FRANCISCO, CALIFORNIA (SFO), FOR 20 DEC. 2022

Model Inputs Including, for Example:

<u>Land Cover/Land Use Type:</u>

Land cover used in the model is the Moderate Resolution Imaging Spectroradiometer 30 arc sec data with lakes.

<u>Local Topography:</u>

The Mellor-Yamada-Nakanishi-Niino (MYNN) surface layer and 3rd-order Planetary Boundary Layer (PBL) physics schemes are used.

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-8.3.5-1 below. More variables are calculated but output is reduced to save storage size and costs (as discussed in the next section).

**TABLE PG&E-8.3.5-1:
WEATHER VARIABLES**

Variable	Description
Q2	Water vapor mixing ratio
T2	Temperature at 2m
PSFC	Surface pressure
U10	10m u wind component
V10	10m 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

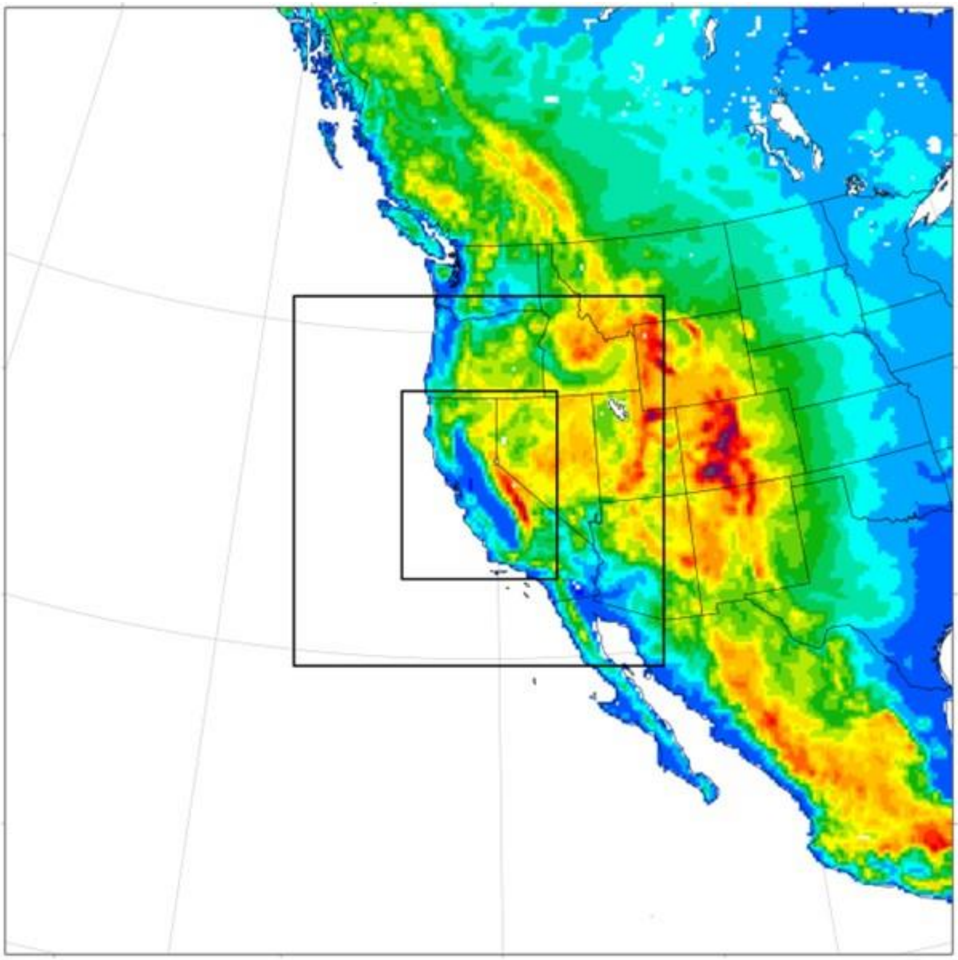
Operational meteorologists use our high-resolution weather model daily to forecast temperatures, storm impact, and PSPS events. Data are typically reviewed multiple times per day by multiple SMEs. In addition, we have numerical weather prediction experts on staff that have reviewed model physics and output.

Spatial Granularity of Forecasts

The horizontal resolution is 2 x 2 km for the control and ensemble forecast. On demand forecasts during high-risk periods can be manually scheduled by SMEs and provide data every 0.67 x 0.67 km.

Below is an example of our nested domain configuration with nested grids, in Figure PG&E-8.3.5-3.

FIGURE PG&E-8.3.5-3:
DIAGRAM OF NESTED DOMAIN CONFIGURATION WITH NESTED GRIDS



Note: The innermost domain covers the entire PG&E territory with a 2 x 2 km grid cell lattice.

In addition, the 2 x 2 km forecasts are downscaled with Wind Ninja to provide wind forecasts every 250 x 250 m.

The vertical grid has 51 levels and a 20 hectopascal top of atmospheric pressure.

Time Horizon of the Weather Forecast Throughout the Service Territory

The weather forecast has a time horizon of 129 hours (5 and a half days).

8.3.5.2 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 across a large domain such as PG&E and requires a large amount of storage.

- Each day, we receive 1.152 terabytes of weather forecast data from our high-resolution model. For reference to a better-known unit, 1 terabyte is equal to a million megabytes. 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, LFM models or climatological datasets.

- To cover our entire service territory, our 2 x 2 km domain consists of 396 grid cells along the x axis and 480 along the y, for a total amount equaling 190,080 (396 X 480) 2 x 2 km grid cells.

- There are a total of 18 high resolution simulations completed each day (4x/day for the control and 2x/day for the remaining 7 members of the ensemble). 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 441,365,760 data points generated per day (190,080 grid cells X 18 runs/day X 129 hours/run). There are 15 variables output at the surface, and 51 vertical levels (z) with output as well. Discounting output from the vertical levels, there are ~7 billion data points output each day across the model domain at a 2 x 2 km resolution at the surface alone. If our model resolution increased from 2 x 2 km to 1 x 1 km, this would quadruple the output. 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 other costs to run more and more granular dynamic weather models.

As weather is a non-linear, chaotic system we are limited in our ability to perfectly forecast weather as has been well documented in the literature. For example, a paper on chaos and weather prediction from the European Centre for Medium-Range Weather states:

> 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. As a consequence, 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.[150]

8.3.5.3 Planned Improvements

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;*

For each planned improvement, the electrical corporation must provide the following in Table 8-31:

- *<u>Description</u>: A description of the planned initiative activity;*
- *<u>Impact</u>: Reference to and description of the impact of the initiative activity on each risk and risk component;*
- *<u>Prioritization</u>: A description of the x% risk impact (see Section 8.1.1.2 for explanation); and*
- *<u>Schedule</u>: A description of the planned schedule for implementation.*

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150 ECMWF Chaos and Weather Prediction. See Appendix E.

TABLE 8-31:
PLANNED IMPROVEMENTS TO WEATHER FORECASTING SYSTEMS

System	Description	Impact	X% Risk Impact	Implementation Schedule
Please see below for Narrative description.	N/A	N/A	N/A	N/A

Increase in Model Validation

We plan to continue our externally driven quarterly validation efforts. We are evaluating if we can add the High-Resolution Rapid Refresh model to the validation reports.

Increase in Spatial Granularity

There are currently no planned increases in granularity.

Decrease in Limitations by Removal of Assumptions

There are no plans currently.

Increase in Input Data Quality

There are no plans currently.

Increase in Related Frequency

There are no plans currently.

8.3.5.4 Evaluating Mitigation Initiatives

The electrical corporation must describe its procedures for the ongoing evaluation of the efficacy of its weather forecasting program.

PG&E has internal SMEs who are trained in the fields of meteorology, atmospheric science, and data science.

We have 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. They have extensive experience building and running the WRF model for several partners around the world. The second vendor has extensive model expertise, especially in California, and has worked extensively with other California utilities to build custom model solutions for their operations. The second vendor was selected as the vendor to perform validation and provide expertise and guidance on the optimal model configuration for testing.

We provide a third layer of validation and have team members with advanced degrees in meteorology with a combined 20 years-experience in the numerical weather prediction area.

These three layers of internal and external experts meet regularly to discuss current capabilities and we validate model performance on a quarterly basis. In addition, we openly share our model data with the San Jose State Wildfire Interdisciplinary Research Center.

8.3.5.5 Enterprise System for Weather Forecasting

In this section, the electrical corporation must provide an overview of its enterprise system for weather forecasting. This overview must include discussion of:

- *Any database(s) used for storage;*
- *Describe the electrical corporation's internal documentation of its database(s);*
- *Integration with systems in other LOB;*
- *Describe any QA/QC or auditing of its system;*
- *Describe internal processes for updating the enterprise system including database(s); and*
- *Any changes to the initiative since the last WMP submission and a brief explanation as to why those changes were made. Include any planned improvements or updates to the initiative and the timeline for implementation.*

Any Database(S) Utilized for Storage

We use Amazon Web Services (AWS) PostgreSQL and AWS S3 storage to store and process weather data.

Describe the Electrical Corporation's Internal Documentation of Its Database(s)

We have internal documentation regarding compute systems and ecosystems where databases live. These documents include general process and data flow diagrams as well as disaster recovery documentation.

Integration With Systems in other LOB

Weather model data is integrated into other LOBs in a few ways. For example, some legacy business applications require direct read-only database access, and we have automated processes that push data into other enterprise databases. Our preferred method of data delivery is delivery via API.

Describe Any QA/QC or Auditing of Its System

Before deploying a system or database to production, we first test in lower environments in development and QA. Once a database or code is deployed to QA it is evaluated for performance and stability by SMEs and analysts. Through the course of business, meteorologists and analysts work with the data in production to identify issues. Issues are raised and tracked through daily operating reviews.

Our AWS technology stack is initiated in our development environment where most of the code is written. When a product is approved by our SMEs who review inputs and outputs in the development environment, it is deployed to our QA environment for testing and general stability. After passing this test, a product is deployed to our production environment where it is considered complete and ready to be disseminated throughout the Company. Our QA environment is also our backup server, so it is important for that environment to match our production environment to the extent possible.

Describe Internal Processes for Updating the Enterprise System Including Database(s)

Any changes to the enterprise system or databases follow a logical deployment cycle through lower environments through to production.

Any Changes to the Initiative Since the Last WMP Submission and a Brief Explanation as to Why Those Changes Were Made. Include Any Planned Improvements or Updates to the Initiative and the Timeline for Implementation.

No changes have been made to the weather databases since the last WMP submission. No substantive changes are planned. We plan to continue using databases and tools available in the AWS ecosystem.

8.3.6 Fire Potential Index

The electrical corporation must describe its process for calculating its fire potential index (FPI) or a similar landscape scale index used as a proxy for assessing real-time risk of a wildfire under current and forecasted weather conditions. The electrical corporation must document the following:

- *Its existing calculation approach and how its FPI is used in its operations;*
- *The known limitations of its existing approach; and*
- *Implementation schedule for any planned changes to the system.*

Reference the Utility Initiative 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 8.3.5.2.

8.3.6.1 Existing Calculation Approach and Use

The electrical corporation must describe.

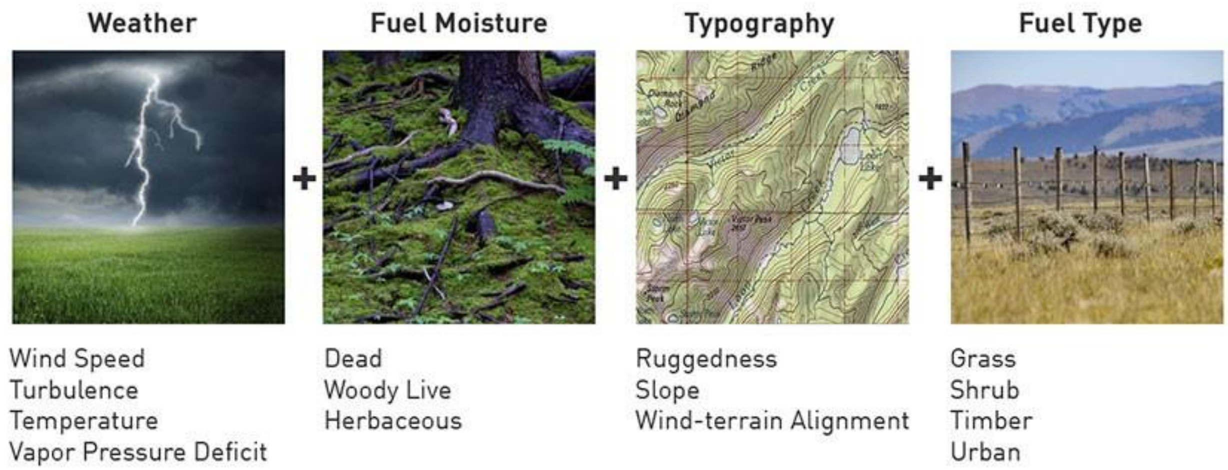
- *How it calculates its own FPI or if uses an external source, such as the United States Geological Survey; and*
- *How it uses its or an FPI in its operations.*
- *Additionally, if the electrical corporation calculates its own FPI, it must provide tabular information regarding the features of its FPI. Table 8-32 provides a tabular list of features.*

To better understand and predict the potential for large and catastrophic fires to occur across our service territory, we developed the FPI Model in 2015 and have improved it several times since. The FPI Model combines fire weather parameters (wind speed, temperature, and vapor pressure deficit), dead and live fuel moisture data, topography, and fuel model data to predict the probability of large and/or catastrophic fires.

The FPI Model was trained on an enhanced fire occurrence dataset that combines agency fire information with sub-daily growth from satellite fire detections. The FPI Model is used as a daily and hourly tool to drive operational decisions to reduce the risk of utility-caused fires. On a day-by-day basis, the FPI Model informs crews and operators what precautions must be taken to reduce the risk of fire ignitions as directed by utility standards. The FPI Model also provides us information about the potential need for and execution of Public Safety Power Shutoff events.

Below, in Figure PG&E-8.3.6-1, highlights the main Fire Potential Index features.

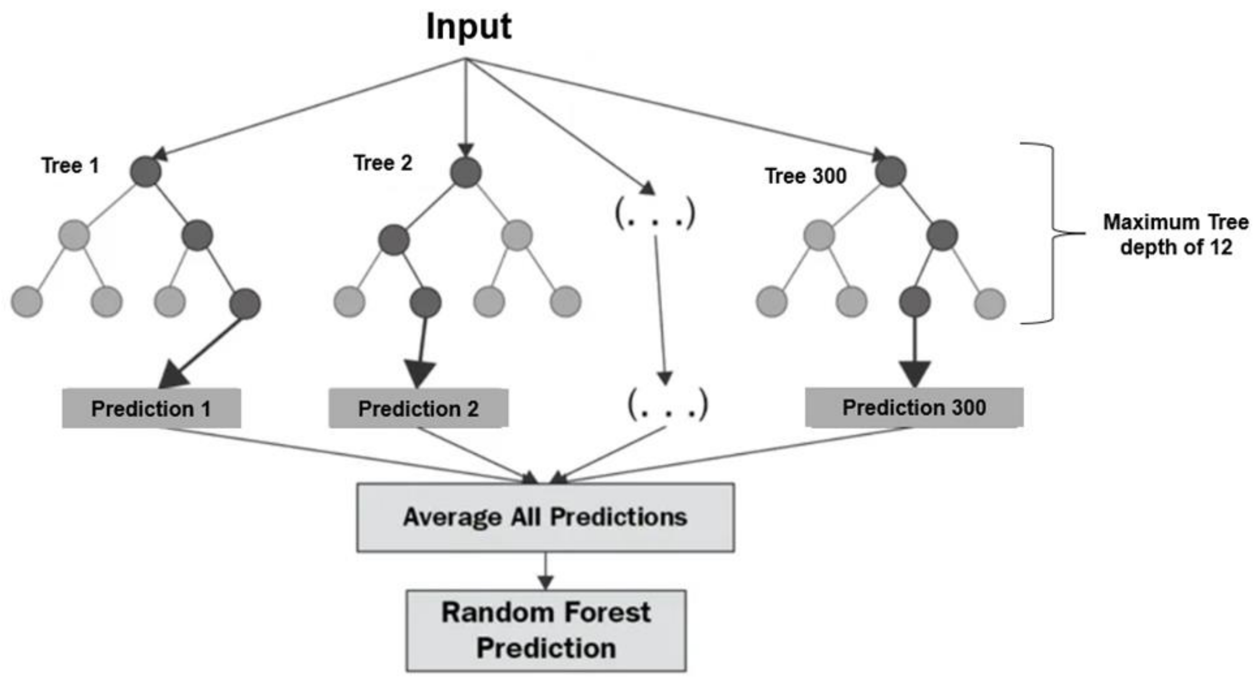
FIGURE PG&E-8.3.6-1:
FPI MODEL FEATURES



The FPI model leveraged the 2 x 2 kilometer (km) weather and fuels 30+ year climatology dataset along with an enhanced fire occurrence dataset during a model feature and methodology evaluation. 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 model types. Model results were tested using a train-test split ratio of 70 percent-30 percent. This involved training the models with 70 percent of the input data and testing predictions with the remaining 30 percent.

We ultimately chose a Balanced Random Forest Classification Machine Learning (ML) model (Figure PG&E-8.3.6-2 below) for FPI based on model performance. Random Forest's framework allows collinear features and models non-linearities in their relationships. The final configuration contains 300 random trees with a tree max depth of 12. The diagram below presents a high-level overview of the FPI Random Forest Classification ML model.

**FIGURE PG&E-8.3.6-2:
FPI RANDOM FOREST MODEL**



The list of model features used in the ML FPI model are discussed in this section and grouped in four main categories: (1) Weather, (2) Fuel Moisture, (3) Topography, and (4) Fuel Type. The ML application has advantages over other models like linear regression because the model learns how features may interact non-linearly to contribute to catastrophic fire spread.

The weather data is sourced from the 2 x 2 km weather forecast model and 31-year climatology. The source of this information is from a numeric weather prediction expert vendor, DTN Weather Solutions. The dead fuel moisture across multiple classes and Live Fuel Moisture – Chamise is sourced from coupling the weather and climatology to models developed by Atmospheric Data Solutions (ADS). New measures of live fuel moistures that were added to the 2021 version of the FPI model were sourced from Technosylva. These take advantage of remote sensing and a model application to estimate the amount of available moisture in woody and herbaceous plant species.

Topography characteristics were also evaluated for 2021. The features included in the 2021 FPI include a measure of terrain ruggedness, which provides a measure of the terrain change in slope and aspect in each 2 x 2 km model grid cell. The slope is also considered and is shown to have a positive effect on fire size where there is existence of steep slopes. Finally, a dynamic wind-terrain alignment factor is computed for each hour to provide an assessment of the wind-terrain alignment in each 2 x 2 km grid cell. During Diablo wind events, scientific literature has shown that when the wind flow is perpendicular to terrain features, winds can accelerate down the lee of the terrain feature. During model testing, a similar pattern emerged, which shows that winds that are perpendicular to terrain (upslope or downslope winds) have a positive relationship to fire size compared to terrain-aligned (cross slope) winds.

Finally, a continuous fuel model type is considered in each 2 x 2 km model grid cell. This information is sourced and routinely updated from Technosylva. The fuel model map baseline is the latest iteration from LANDFIRE but is adjusted to account for recent burn scars and vegetation regrowth after fire that are not considered in LANDFIRE. The native resolution of the fuel model map is 30 x 30-meter (m) resolution. For each 2 x 2 km model grid cell, the fraction of six fuel model categories is computed to provide the fraction of that area that is urban, grass, grass-shrub, shrub, Timber-litter or Timber-understory. We worked closely with Technosylva fire scientists to consolidate the 50+ fuel model types into these six parent categories.

Each model feature used in the FPI is presented in Figure PG&E-8.3.6-3 and Table 8-32 below.

FIGURE PG&E-8.3.6-3:
FPI MODEL SCHEMATIC

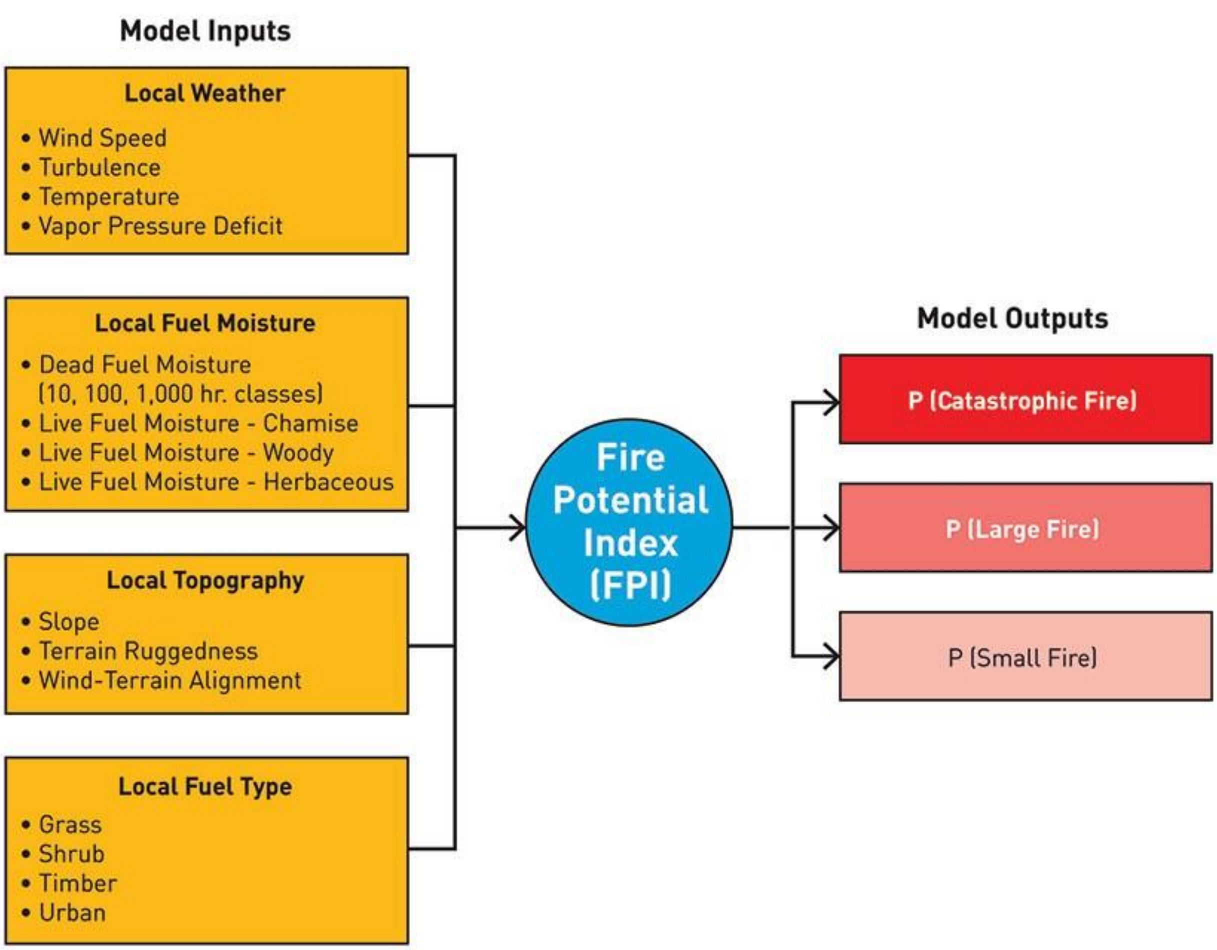


TABLE 8-32:
FIRE POTENTIAL INDEX MODEL FEATURES

Feature Group	Feature	Altitude	Description	Source	Update Cadence	Spatial Granularity	Temporal Granularity
Weather	Temperature	Surface	Temperature at the surface in Fahrenheit	Pacific Gas and Electric Company Operational Mesoscale Modeling System (POMMS)	4x per day	2 km	Hourly
Weather	Vapor Pressure Deficit	Surface	Measure of lack of water vapor relative to saturation in millibars	POMMS	4x per day	2 km	Hourly
Weather	Wind Speed (sustained)	Surface	Wind speed at the surface in mph	POMMS	4x per day	2 km	Hourly
Weather	Wind Speed (sustained)	300 m	Wind speed at 300 m above surface in mph	POMMS	4x per day	2 km	Hourly
Weather	Friction Velocity (u*)	Surface	Wind shear stress in velocity terms.	POMMS	4x per day	2 km	Hourly
Weather	Turbulent Kinetic Energy	50 m	Kinetic energy per unit mass observed in eddies characteristic of turbulent flow in Joules/kilograms	POMMS	4x per day	2 km	Hourly
Fuel Moisture	Dead Fuel Moisture – 1000hr	Surface	1000-hour fuel moisture content	POMMS & ADS	4x per day	2 km	Hourly
Fuel Moisture	Dead Fuel Moisture – 100hr	Surface	100-hour fuel moisture content	POMMS & ADS	4x per day	2 km	Hourly
Fuel Moisture	Dead Fuel Moisture – 10hr	Surface	10-hour fuel moisture content	POMMS & ADS	4x per day	2 km	Hourly
Fuel Moisture	Live Fuel Moisture – Chamise New	Surface	Live fuel moisture content of Chamise (new growth) species	POMMS & ADS	Daily	2 km	Daily
Fuel Moisture	Live Fuel Moisture – Herbaceous	Surface	Live fuel moisture content of herbaceous species	Technosylva	Daily	2 km	Daily

TABLE 8-32:
FIRE POTENTIAL INDEX MODEL FEATURES
(CONTINUED)

Feature Group	Feature	Altitude	Description	Source	Update Cadence	Spatial Granularity	Temporal Granularity
Fuel Moisture	Live Fuel Moisture – Woody	Surface	Live fuel moisture content of woody species	Technosylva	Daily	2 km	Daily
Topography	Terrain Ruggedness Mean	Surface	Terrain ruggedness average in POMMS grid cell.	United States Geological Survey (USGS) 30 m DEM (Digital Elevation Model)	USGS 30 m DEM	30 m -> 2 km	Static after being updated
Topography	Slope Degree Mean	Surface	Slope of terrain averaged over POMMS grid cell.	USGS 30m DEM	USGS release cadence	30 m -> 2 km	Static after being updated
Topography	Wind-Terrain Alignment	Surface	Alignment between wind direction and dominant aspect	POMMS & USGS 30 m DEM	4x per day	30 m -> 2 km	Hourly
Fuel Type	Urban	Surface	Fraction of fuel category in POMMS grid cell attributed to urban	Technosylva	At least once per year	30 m -> 2 km	Static after being updated
Fuel Type	Grass-Shrub	Surface	Fraction of fuel category in POMMS grid cell attributed to grass-shrub	Technosylva	At least once per year	30 m -> 2 km	Static after being updated
Fuel Type	Shrub	Surface	Fraction of fuel category in POMMS grid cell attributed to shrubs	Technosylva	At least once per year	30 m -> 2 km	Static after being updated
Fuel Type	Timber Litter	Surface	Fraction of fuel category in POMMS grid cell attributed to timber litter	Technosylva	At least once per year	30 m -> 2 km	Static after being updated
Fuel Type	Grass	Surface	Fraction of fuel category in POMMS grid cell attributed to grasslands	Technosylva	At least once per year	30 m -> 2 km	Static after being updated
Fuel Type	Timber Understory	Surface	Fraction of fuel category in POMMS grid cell attributed to timber understory	Technosylva	At least once per year	30 m -> 2 km	Static after being updated

8.3.6.2 Known Limitations of Existing Approach

The electrical corporation must describe any known limitations of current FPI calculation.

The FPI model uses a ML random forest framework. We have found ML outperforms simpler FPI models discussed in our earlier WMPs,[151] even though simpler models tend to be easier to understand, explain, and verify how small changes affect results.

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 4-5 day forecast horizon. The FPI Model is driven largely from the weather forecasts and will have similar limitations as weather forecasting (see Section 8.3.5.2).

8.3.6.3 Planned Improvements

The electrical corporation must describe its planned improvements for its FPI including a description of the improvement and the planned schedule for implementation.

Utility Initiative Tracking ID: SA-04; SA-05; SA-06

By the end of 2025 we will evaluate enhancements to the FPI and IPW models. This involves testing new features and types of model configurations that could improve model skill. At present we do not know if model skills can be improved, but we will attempt to do so.

151 2021 WMP – Section 7.3.2 Situational Awareness and Forecasting, and/or 2022 WMP – Section 4.5.1(f) FPI Model.

8.4 Emergency Preparedness

8.4.1 Overview

Each electrical corporation must develop and adopt an emergency preparedness plan in compliance with the standards established by the California Public Utilities Commission (CPUC), pursuant to Public Utilities Code (Pub. Util. Code) Section 768.6(a). Wildfires and Public Safety Power Shutoff (PSPS) introduce unique risk management challenges requiring the electrical corporation to evaluate, develop, and implement wildfire- and PSPS-specific emergency preparedness activities as part of a holistic emergency preparedness strategy.

In this section, the electrical corporation must identify objectives for the next 3- and 10-year periods, targets, and performance metrics related to the following emergency preparedness programmatic areas:

- *Wildfire and PSPS emergency preparedness plan;*
- *Collaboration and coordination with public safety partners;*
- *Public notification and communication strategy;*
- *Preparedness and planning for service restoration;*
- *Customer support in wildfire and PSPS emergencies; and*
- *Learning after wildfire and PSPS events.*

Wildfire and PSPS Emergency Preparedness Plan

PG&E's Emergency Preparedness and Response (EP&R) organization is responsible for emergency preparedness, prevention, response, mitigation, and recovery in responding to wildfire and PSPS emergency incidents. EP&R's strategy focuses on initiatives that ensure we remain prepared to respond to these events in ways that benefit our customers and communities.

As part of PG&E's wildfire and PSPS emergency preparedness efforts, EP&R annually publishes the Company Emergency Response Plan (CERP), in Appendix E, that provides guidance on managing emergencies and establishes processes that are scalable to any hazard, including Wildfire and PSPS events. For more details, please see Section 8.4.2.1.

Collaboration and Coordination with Public Safety Partners

EP&R advances PG&E's response to emergencies by improving governance, strengthening coordination among PG&E's functional areas, and improving collaboration with external partners such as the Federal Emergency Management Agency (FEMA) and the California Governor's Office of Emergency Services (Cal OES).

Public Notification and Communication Strategy

PG&E's media relations strategy and the channels that we implement before, during, and after an emergency incident or event is presented in the CERP Emergency Communications Annex. For PSPS Events, PG&E uses multiple communications channels to notify the public. These include direct customer notifications, PSPS Address Alerts, information on the PG&E website, information releases to local media, and Live Agent Call Center Support. PG&E's Emergency Communications Annex provides an overview of PG&E's strategy for any type of emergency.

Preparedness and Planning for Service Restoration

All PG&E coworkers involved in post-incident damage and PSPS all clear service restoration rely on the CERP, Wildfire, and PSPS annexes, applicable department emergency plans, and their respective emergency centers' contact list. Our EP&R Strategy & Execution Department determines and posts EOC on-call teams, rotations, and yearly scheduling. Emergency Operations Center (EOC) on-call distribution lists are maintained to ensure team notifications are timely and accurate, including notifications to eight phonetically (Alpha-Hotel) identified, rotating, 24-hour paired teams, as shown in Table PG&E-8.4.1-1 below.

TABLE PG&E-8.4.1-1
EXAMPLE ROTATING EOC TEAM SCHEDULE

Week	Day Shift	Night Shift
1	Alpha	Bravo
2	Charlie	Delta
3	Echo	Foxtrot
4	Golf	Hotel

Customer Support in Wildfire and PSPS Emergencies

In an emergency, primary points of contact for customers can be found on the pge.com website in the PG&E Customer Service Center Brochure. PG&E maintains residential and business Contact Service Centers Monday – Friday, 7:00 a.m. – 7:00 p.m. Additionally, the Residential Customer Service Center is open Saturday, 8:00 a.m. – 5:00 p.m. Automated service is available daily after hours at 1-800-743-5000.

PG&E's Contact Service Center agents are trained in how to handle customers dealing with natural gas and electric emergencies. Additionally, they have specific procedures to escalate life-threatening situations. Customer support is expanded through translation services which are available in 240 languages. Providing multilingual, telephonic services, including California Relay Service and/or Telecommunications Device for the Deaf/Teletypewriter (TDD/TTY) for customers who are speech and hearing-impaired, our Contact Service Centers continue to be the primary avenue customers use to report emergencies.

During a PSPS event, PG&E decides whether to implement the PSPS call strategy to ensure elevated service with minimal wait times for customers potentially affected by an active PSPS event. The PSPS call strategy includes maintaining full staffing across Contact Center Operations, training Credit and Billing representatives to be able to handle PSPS call types, and only accepting emergency-related calls (including calls related to downed wires, gas leaks, outages, and PSPS) when notifications are sent to over 100,000 customers for an active PSPS event.

During large outages, PG&E may provide Live Agent Outbound calls to customers, typically medical baseline and/or life support customers, when the EOC is activated.

Learning After Wildfire and PSPS Events

PG&E continually evaluates threats, hazards, risks, After Action Reviews (AAR), and related post-wildfire and PSPS event or exercise corrective actions as part of our multi-year training strategy. Company-wide in scope, this program is described in the PG&E Multi-Year Training and Exercise Plan 2023-2025 (MYTEP) (see Appendix E). PG&E annually trains personnel who have emergency roles on required actions in coordination with internal and external incident and event stakeholders. This training is designed to resolve problems identified during our responses to incidents, events, and exercises.

8.4.1.1 Objectives

Each electrical corporation must summarize the objectives for its 3-year and 10-year plans for implementing and improving its emergency preparedness. These summaries must include the following:

- *Identification of which initiative(s) in the Wildfire Mitigation Plan (WMP) the electrical corporation is implementing to achieve the stated objective, including Utility Initiative Tracking IDs;*
- *Reference(s) to applicable codes, standards, and best practices/guidelines and an indication of whether the electrical corporation exceeds an applicable code, standard, or regulation;*
- *Method of verifying achievement of each objective;*
- *A completion date for when the electrical corporation will achieve the objective; and*
- *Reference(s) to the WMP section(s) or appendix, including page numbers, where the details of the objective(s) are documented and substantiated.*

This information must be provided in Table 8-33 for the 3-year plan and Table 8-34 for the 10-year plan. Minimum acceptable level of information is provided below.

PG&E is currently working with internal and external stakeholders, including Cal OES, to develop and implement activities that exceed compliance requirements in CPUC General Order (GO) 166, Standards for Operation, Reliability, and Safety During Emergencies and Disasters. PG&E's 3-year and 10-year emergency preparedness foundation builds on: (1) PG&E's mission, goals, objectives, and milestones for our Emergency Management Program; (2) our method for preparedness plan implementation; and (3) a maintenance process, which includes a method and schedule for evaluation and revision.

To successfully meet these provisions, PG&E uses course names to identify required training. We track employee and external contractor qualifications based on seminar attendance, training academy records, and successful participant exercise completion. Objectives are defined and tracked for each individual emergency preparedness course, exercise, and drill. We also track completion dates for each program.

Additional details regarding these initiatives, including supporting documentation, is found in Section 8.4.2.

- Table 8-33 and Table 8-34 Information Summary: In Table 8-33 and Table 8-34, we are providing the objective name (Objective Name), a description of the objective (Objective Description), the anticipated outlook of the objective (3-Year/10-Year Outlook), the planned due date for the objective (Completion Date), the applicable Initiative Tracking ID ive Tracking ID), "Applicable Regulations, Codes, Standards, and Best Practices", "method of verification", and "section and page #" references. As noted in Section 7.2.1, "Applicable Regulations, Codes, Standards, and Best Practices," "method of verification," and "section and page #" columns are not a part of the objective. Instead, the controlling objective information is in the "Objective Description" and "Completion Date" columns.

- Reporting: Unless changed through the Office of Energy Infrastructure Safety's (Energy Safety) Change Order process, PG&E will use the objectives in Table 8-33 and Table 8-34 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 2023-2025 WMP, we discuss current plans for wildfire-related activities beyond the objectives in Table 8-33 and Table 8-34. The timing and scope of these additional activities and work may change. We will not be reporting on these plans or activities in our QDR, QN, or ARC because they are not objectives, but are descriptions of plans and activities in our 2023-2025 WMP to provide a complete picture of our wildfire mitigation activities.

- External Factors: All objectives in the below Table 8-33 and Table 8-34 are subject to External Factors which represent reasonable circumstances which may impact execution against objectives including, but not limited to, physical conditions, landholder refusals, environmental delays, 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 ID: We are including Initiative Tracking IDs in each section that has associated targets and objectives. Table 8-33 and Table 8-34 display the Tracking IDs we are implementing to tie the objectives to the narratives and initiatives in the WMP. The Initiative Tracking IDs will also be used for reporting in the QDR.

TABLE 8-33:
EMERGENCY PREPAREDNESS INITIATIVE OBJECTIVES (3-YEAR PLAN)

Objective Name	Objective Description	Applicable Initiative(s), Tracking ID(s)	Applicable Regulations, Codes, Standards, and Best Practices (See Note)	Method of Verification (i.e., program)	Completion Date	Reference (Section and Page #)
Complete PSPS and Wildfire Tabletop and Functional Exercises	Complete PSPS and Wildfire Tabletop and Functional Exercise annually in compliance with the guiding principles of the Homeland Security Exercise Evaluation Program (HSEEP)	EP-01	PSPS exercise requirements: • Phase 1: Decision (D.) 19-05-042 • PSPS OII: D.12-06-014 • PSPS Phase 2 D.20-05-051 • PSPS Phase 3 D.21-06-034 Wildfire exercise: 1) Rulemaking (R.) 18-12-005 Appendix A (b) De-energization Exercises	Check-in/check-out records or After-Action Review (AAR) items	11/30/2023 11/30/2024 11/30/2025	Section 8.4.2.3.1 Page 667

TABLE 8-33:
EMERGENCY PREPAREDNESS INITIATIVE OBJECTIVES (3-YEAR PLAN)
(CONTINUED)

Objective Name	Objective Description	Applicable Initiative(s), Tracking ID(s)	Applicable Regulations, Codes, Standards, and Best Practices (See Note)	Method of Verification (i.e., program)	Completion Date	Reference (Section and Page #)
Maintain all hazards planning and preparedness program in 2023-2025	Maintain the All Hazards Planning and Preparedness Program to provide emergency response and safely and expeditiously restore service.	EP-02	GO 166 Standard 1 and Standard 1.J ISO 45001 and 14001	Check-in/check-out records or After-Action Review (AAR) items	12/31/2025	Section 8.4.3.1 Page 683
Expand all hazards planning to include additional threats and scenarios in 2023-2025	Expand the all hazards planning program to include additional threats and scenarios.	EP-04	GO 166 in its entirety	Check-in/check-out records or After-Action Review (AAR) items	12/31/2025	Section 8.4.3.1 Page 683

TABLE PG&E-8-34:
EMERGENCY PREPAREDNESS INITIATIVE OBJECTIVES (10-YEAR PLAN)

Objective Name	Objective Description	Applicable Initiative(s), Tracking ID(s)	Applicable Regulations, Codes, Standards, and Best Practices (See Note)	Method of Verification (i.e., program)	Completion Date	Reference (Section and Page #)
Maintain all hazards planning and preparedness program in 2026-2032	Maintain the all hazards planning and preparedness program to provide emergency response and safely and expeditiously restore service.	EP-03	GO 166 Standard 1 and Standard 1.J ISO 45001 and 14001	Check-in/check-out records or After-Action Review (AAR) items	12/31/2032	Section 8.4.3.1 Page 683
Expand all hazards planning to include additional threats and scenarios in 2026-2032	Expand the all hazards planning program to include additional threats and scenarios.	EP-05	GO 166 in its entirety	Check-in/check-out records or After-Action Review (AAR) items	12/31/2032	Section 8.4.3.1 Page 683

8.4.1.2 Targets

Initiative targets are forward-looking quantifiable measurements of activities identified by each electrical corporation in its WMP. Electrical corporations will show progress toward completing targets in subsequent reports, including QDRs and WMP Updates.

The electrical corporation must list all targets it will use to track progress on its emergency preparedness for the next three years (2023-2025). Energy Safety's Compliance Assurance Division and third parties must be able to track and audit each target.[152] *For each initiative target, the electrical corporation must provide the following:*

- *Utility Initiative Tracking IDs;*
- *Projected targets for the three years of the Base WMP and relevant units;*
- *The expected "x% risk impact" for each of the three years of the Base WMP. The expected x% risk impact is the expected percentage risk reduction per year, as described in Section 7.2.2.2.; and*
- *Method of verifying target completion.*

The electrical corporation's targets must provide enough detail to effectively inform efforts to improve the performance (i.e., reduction in wildfire consequence) of the electrical corporation's emergency preparedness initiatives.

- Table 8-35 Information Summary: In Table 8-35, we are providing the target name (Target Name), the applicable Initiative Tracking ID (Initiative Tracking ID) and a description of the Target for each applicable year (2023 Target & Unit, 2024 Target & Unit, 2025 Target & Unit), the "% Risk Impact" for each respective year, and the method of verification. As noted in Section 7.2.1, the % Risk Impact and method of verification columns are not a part of the Target. Instead, the controlling target information is in the "Target & Unit" columns for each respective year.
- Utility Initiative Tracking ID: We are including Initiative Tracking IDs in each section that has associated targets and objectives. Table 8-35 displays the Tracking IDs we are implementing to tie the targets to the narratives and initiatives in the WMP. The Initiative Tracking IDs will also be used for reporting in the QDR.
- Reporting: Unless changed through Energy Safety's Change Order process, PG&E will use the Targets in Table 8-35 below for quarterly compliance reporting including the QDR, QN, and the ARC. It is also important to note that throughout this 2023-2025 WMP, we discuss current plans for wildfire-related activities in addition to the Targets in Table 8-35. The timing and scope of these additional activities and work may change. We will not be reporting on these plans or activities in our QDR, QN, or ARC because they are not Targets but are descriptions of plans and

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152 *Annual information included in this section must align with Table 1 of the QDR.*

activities in our 2023-2025 WMP to provide a complete picture of our mitigation activities.

- % Risk Impact: The % Risk Impact provided in Table 8-35 is calculated based on the risk reduction of the mitigation initiative divided by total overall utility risk as defined in Section 6.4.2, Section 7.2.2.2, and Section 7.2.2.3. The % Risk Impact provided is an estimate based on the best available workplans applied against the latest risk models as of time of this filing. Please note, 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, for inspection and line sensor related targets, since inspections in of themselves do not reduce risk, instead we provided an “Eyes-on-Risk” value to provide insights into the level of risk being assessed.

- External Factors: All targets in the below Table 8-35 are subject to External Factors which represent reasonable circumstances which may impact execution against targets including, but not limited to, physical conditions, landholder refusals, environmental delays, 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.

- High Fire Threat District (HFTD), High Fire Risk Area (HFRA), Buffer Areas: Unless stated otherwise, all initiative work described in Table 8-35 involves work or audits on units or equipment located in, traversing, energizing, or protecting units or equipment in HFTD, HFRA, or Buffer Zone areas.

TABLE 8-35:
EMERGENCY PREPAREDNESS INITIATIVE TARGETS BY YEAR

Target Name	Initiative Activity Tracking ID	Reference Section	2023 Target & Unit	x% Risk Impact 2023	2024 Target & Unit	x% Risk Impact 2024	2025 Target & Unit	x% Risk Impact 2025	Method of Verification
Annually review, and revise if appropriate, the Company Emergency Response Plan (CERP) and the two wildfire-related annexes (the Wildfire Annex and the PSPS Annex)	EP-06	8.4.3.1	3 documents (1 CERP and 2 wildfire-related annexes)	N/A	3 documents (1 CERP and 2 wildfire-related annexes)	N/A	3 documents (1 CERP and 2 wildfire-related annexes)	N/A	Review and revise, as required.

8.4.1.3 Performance Metrics

Performance metrics indicate the extent to which an electrical corporation's WMP is driving performance outcomes. Each electrical corporation must:

- *List the performance metrics the electrical corporation uses to evaluate the effectiveness of its emergency preparedness in reducing wildfire and PSPS risk.*

For each of these performance metrics listed, the electrical corporation must:

- *Report the electrical corporation's performance since 2020 (if previously collected);*
- *Project performance for 2023-2025; and*
- *List method of verification.*

The electrical corporation must ensure that each metric's name and values are the same in its WMP reporting as its QDR reporting (specifically, QDR Table 2 and QDR Table 3). Metrics listed in this section that are the same as performance metrics required by Energy Safety and reported in QDR Table 2 (Performance Metrics) must match those reported in QDR Table 2. Metrics listed in this section that are not the same as any of the performance metrics identified by Energy Safety and reported in QDR Table 2 must match those reported in QDR Table 3.

The electrical corporation must:

- *Summarize its self-identified performance metric(s) in tabular form; and*
- *Provide a brief narrative that explains trends in the metrics.*

Table 8-36 provides an example of the minimum acceptable level of information.

Table 8-36 below shows our Emergency Preparedness performance metrics results from 2020-2022 and projected results from 2023-2025.

PG&E tracks the number of distribution outages while Enhanced Powerline Safety Settings (EPSS) is enabled. Recognizing that there is year-to-year variability in outage activity, we are taking steps to reduce the number of outages that occur while EPSS is enabled. PG&E launched EPSS as a pilot project in 2021 and in 2022 expanded the scope of EPSS to all High Fire Risk Areas (HFRA) and select adjacent EPSS buffer zones. We are projecting a decrease in the number of events by approximately 2 percent each year from 2023-2025 compared to the number of events in 2022.

Performance metrics related to frequency, scope, and duration of PSPS events are largely weather dependent and customer impact will fluctuate depending on the meteorological conditions and grid configuration at the time of each event.

Using our 2023 workplans for undergrounding and Motorized Switch Operator replacements, PG&E projected PSPS metrics into 2023 and keeps those values static for 2024-2025. PG&E anticipates continued improvement from 2023-2025, but we do not yet have final workplans and analysis on the value of those improvements for the following years.

Notifying customers prior to initiation of PSPS event ensures customers are aware of the potential outages and the resources available to them. The metric “number of customers notified prior the initiation of PSPS event” is largely weather dependent as this metric will corelate with the frequency, scope, and duration of PSPS events.

TABLE 8-36:
EMERGENCY PREPAREDNESS PERFORMANCE METRICS RESULTS BY YEAR

Performance Metrics	2020	2021	2022	2023 Projected	2024 Projected	2025 Projected	Method of Verification (e.g., Third-Party Evaluation, QDR)
Number of EPSS Events	[a]	[a]	2,375	2,350	2,300	2,250	QDR[b]
Duration of PSPS Events (in Customer Hours)	22.3 million	2.5 million	0	12.3 million	12.2 million	12.0 million	QDR[c]
Number of Customers Notified Prior to Initiation of PSPS Events	869,000	181,000	0	457,000	451,000	445,000	QDR[d]

(a) No data available as PG&E's EPSS program started only from 2022.
(b) QDR Table 10, QDR No. 1d.
(c) QDR Table 10, QDR No. 1c.
(d) QDR Table 10, QDR No. 4c.

8.4.2 Emergency Preparedness 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. The electrical corporation must provide the title of its latest emergency preparedness report, the date of the report, and an indication of whether the plan complies with CPUC R.15-06-009, 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.*

Reference the Utility Initiative Tracking ID where appropriate.

On April 29, 2022, PG&E filed our *ARC with GO 166*[153] for the period July 1, 2020, through December 31, 2021. The report complies with R.15-06-009, D.21-05-019, and GO 166. PG&E evaluates, develops, and integrates GO 166 requirements through ongoing threat, hazard, risk and incident assessments. This helps inform how we conduct AARs and corrective actions aligned with frameworks provided by the National Incident Management System (NIMS), California Standardized Emergency Management System (SEMS), and the NIMS/SEMS component Incident Command System (ICS).

Other relevant CPUC R.15-06-009, D.21-05-019 and GO 166 compliant emergency preparedness plan documents include the *PG&E CERP* and supporting annexes.

Documents that govern PG&E's wildfire and PSPS emergency response and recovery efforts include:[154]

- *PG&E Company Emergency Response Plan (CERP), Version 8.1, dated January 1, 2023;*
- *PG&E Wildfire Annex to the Company Emergency Response Plan, Version 3.0, dated April 1, 2022;*
- *PG&E Emergency Communications Annex to the Company Emergency Response Plan, Version 6, dated June 23, 2022; and*

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153 PG&E GO 166 2020 – 2021 Annual Compliance Report. See Appendix E.

154 See Appendix E.

- *PG&E Public Safety Power Shutoff Annex to the Company Emergency Response Plan, Version 6.0, dated August 25, 2022.*

8.4.2.1 Overview of Wildfire and PSPS Emergency Preparedness

In this section of the WMP, the electrical corporation must provide an overview of its wildfire- and PSPS-specific emergency preparedness plan. At a minimum, the overview must describe the following:

- *Purpose and scope of the plan;*
- *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; and*
  - *Separate overviews and operational flow diagrams for wildfires and PSPS events.*
- *Key personnel, qualifications, and training;*
- *Resource planning and allocation (e.g., staffing);*
- *Drills, simulations, and Tabletop Exercises (TTX);*
- *Coordination and collaboration with public safety partners (e.g., emergency planning, interoperable communications);*
- *Notification of and communication to customers during and after a wildfire or PSPS event; and*
- *Improvements/updates made since the last WMP submission.*

The overview must be no more than six pages.

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 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. Table 8-37 provides an example of the minimum level of content and detail required.

Purpose and Scope of Plan

PG&E's CERP provides guidance to our teams who deliver safe, efficient, and coordinated responses to all hazard emergency incidents affecting gas or electric generation, distribution, storage, transmission systems or any other emergency incident in the PG&E service area. The CERP and its annexes contain: Introduction; Emergency Organization and Responsibilities; Concept of Operations; and Coordination and Communication Instructions. PG&E's CERP and related information is listed in Appendix E.

PG&E's Wildfire Annex to the CERP (Wildfire Annex) covers actions and strategies to prepare for, mitigate, respond to, and recover from incidents related to wildfires that impact PG&E or its customers.

PG&E's Public Safety Power Shutoff Annex to the CERP (PSPS Annex) covers actions and strategies to prepare for, respond to and recover from risk of wildfire ignition related to PG&E assets leading to de-energization for public safety during dry severe weather conditions.

Both the Wildfire Annex and PSPS Annex describe PG&E's internal and external coordination and communication plans and provide an organized and comprehensive approach to wildfire incident support.

PG&E's Emergency Communications Annex to the CERP provides an overview of our communications plans and strategies applicable to any type of emergency.

Overview of Protocols, Policies, and Procedures for Responding to and Recovering from a Wildfire or PSPS 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. The incident classification scale is shown in Table PG&E-8.4.2-1 below and it is applicable to wildfires incidents. The incident classification scale is described in CERP subsection 8.1, Emergency Plan Activation.

TABLE PG&E-8.4.2-1:
INCIDENT CLASSIFICATION SCALE

Color	Description	Response
Red	Catastrophic	• Incident includes multiple emergencies, affects many customers, business operations. • Significant cost and infrastructure risk damage. • Full mobilization of PG&E, contractor, and mutual aid resources. • May have heavy media interest and actual reputational risk. • EOC and Executive Team are activated.
Amber	Severe	• Incident includes extended multiple incidents and affects many customers. • Escalating Company impact. • Resources, contractors, and mutual aid may be shared between regions. • May have heavy media interest and potential reputational risk.
Yellow	Serious	• Incident involves large numbers of customers. • Resources may need to move between regions. • Potential increased, actual, or imminent negative media interest.
Green	Elevated	• A pending or local incident that requires more than routine operations. • Resources may need to move within the region. • Increased media interest.
Blue	Routine	• Incident involves a relatively small number of customers. • Local resources are sufficient. • Little to no media coverage.

The incident classification scale summarizes the actions that may be required in responding to an incident, including interactions with our Meteorology Operations and Analytics team and reliance on our Hazard Awareness and Warning Center (HAWC) situational assessment and awareness capabilities. PG&E uses the California SEMS ICS framework for resource allocation and prioritization from activation to response, recovery, and restoration of services.

Generally, PG&E does not activate the Company EOC for wildfire incident support that can be managed out of one of the19 division-level Operations Emergency Centers (OEC), or at a regional level Regional Emergency Center (REC) activated in support of one or more OECs. PG&E uses the same framework as the SEMS Operational Area concept for emergency organization and structure, with emergencies beginning at the local level (Level 1), which is our base emergency posture.

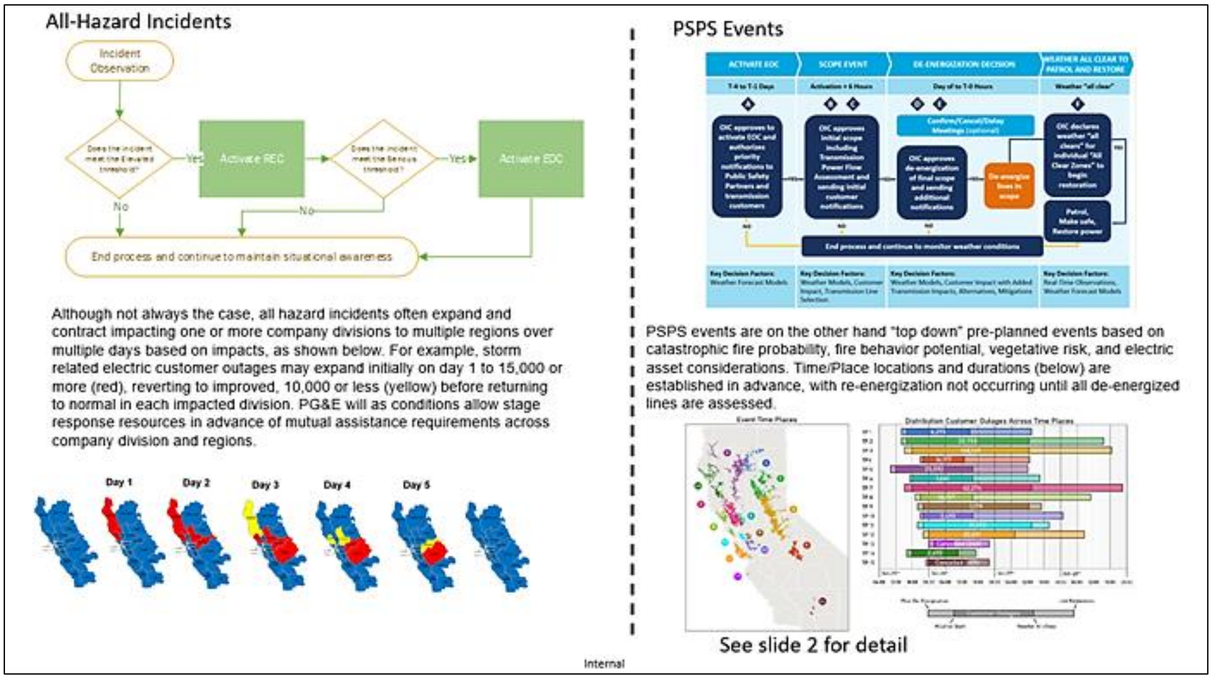
PSPS events are different from all-hazards incidents, including wildfires, where OECs, RECs and the Company EOC are activated as needed in response to incident complexity. PSPS events are "top down" pre-planned events based on catastrophic fire probability, fire behavior potential, vegetative risk, and electric asset considerations. For PSPS events, PG&E's PSPS Officer in Charge, with input from the Company's Vice President-EP&R, on-call EOC Commander, and a representative from our Meteorology department will determine whether conditions warrant activation of the EOC for event management aimed at eliminating fire ignition potential.

Operational Flow Diagrams

Wildfires, like most All-Hazard incidents which are due to factors largely outside of PG&E's control, scale from the "bottom up," working their way from the Company OECs to the RECs, and then to the 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-8.4.2-1 below.

FIGURE PG&E-8.4.2-1:
ALL HAZARD INCIDENTS AND PSPS EVENTS PROCESS COMPARISON



With the above in mind, there are similar linear aspects which apply to All-Hazard incidents and PSPS events alike. One is in the Suppliers, Inputs, Processes, Outputs by Section, and Customers (SIPOC) areas, as shown below in Figure PG&E-8.4.2-2.

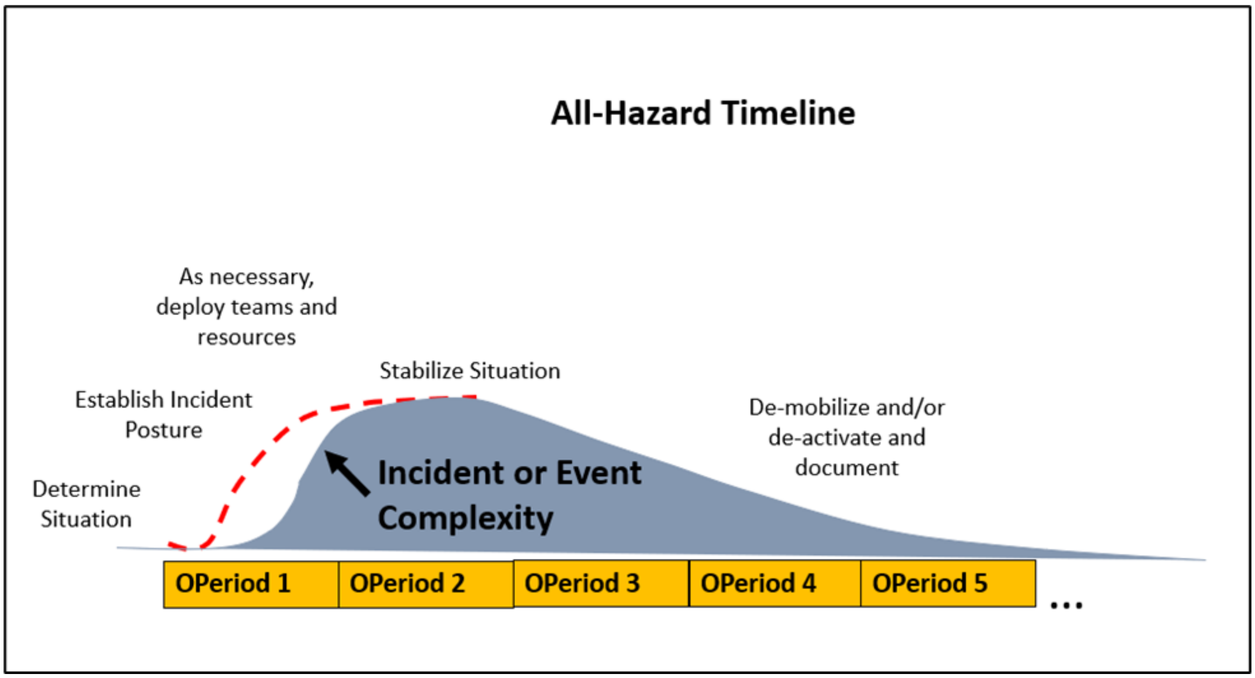
FIGURE PG&E-8.4.2-2:
SUPPLIERS, INPUTS, PROCESSES, OUTPUTS BY SECTION, AND CUSTOMERS AREAS

Suppliers	Inputs	Processes	Outputs by Section	Customers
Lines of Business	Customers	Trigger or Starting Point	Plans - Situation Report	Customers
Government Agencies	Remote Sensing Analytics (Meterology Geomorphology Seismology & other Environmental Threats)	Determine Situation	Command - ICS 210 incident Briefing	Lines of Business
	Lines of Business	Establish Incident Posture	Operations-Resources engaged in Proportion to Need	Leadership
	Government Agencies	As necessary, deploy Teams and Resources	Operations - Incidents Gaps filled	Government Agencies
		Stabilize Situation	EP&R - After Action Report	
		Demobilize and/or Deactivate & Document		
		Ending Point		

Another similar linear aspect between All-Hazard incidents and PSPS events is in the “wave” pattern in the All-Hazard Timeline, as illustrated in Figure PG&E-8.4.2-3, below.

This diagram also highlights another essential difference between All-Hazard and PSPS events. In it, the dashed red line shows how for All-Hazard incidents we are often needing to catch up on resource requirements, thus the gap which eventually closes with incident stabilization. Here, the smaller the gap the better. As it is not possible to predict where damages will occur, we are often challenged with moving resources to areas of greatest need. This is fundamentally different than PSPS events, which because they are planned, do not tend to suffer this gap in resources.

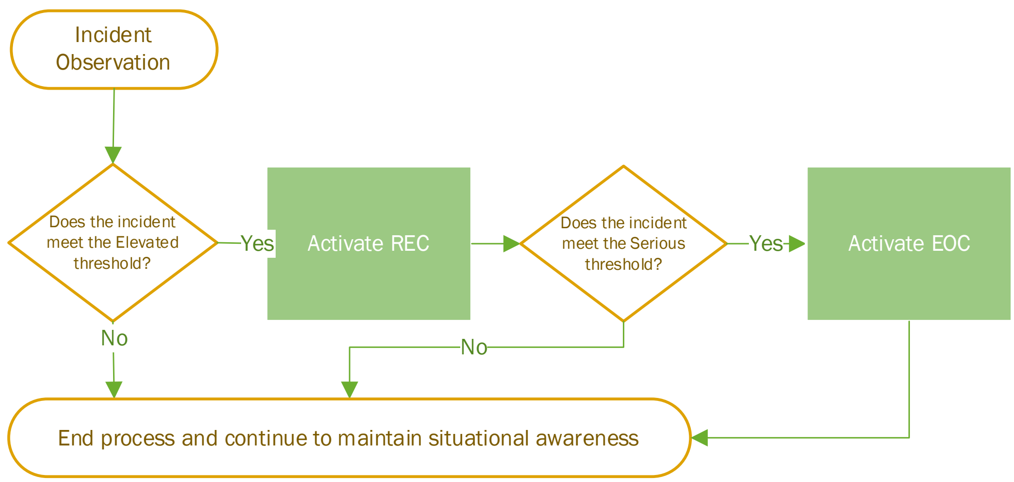
FIGURE PG&E-8.4.2-3:
ALL-HAZARD TIMELINE



Operational Flow Diagram for Wildfires

Key components of PG&E's wildfire emergency response procedures are shown in Figure PG&E-8.4.2-4 below. These actions apply to wildfires and all-hazards incidents generally.

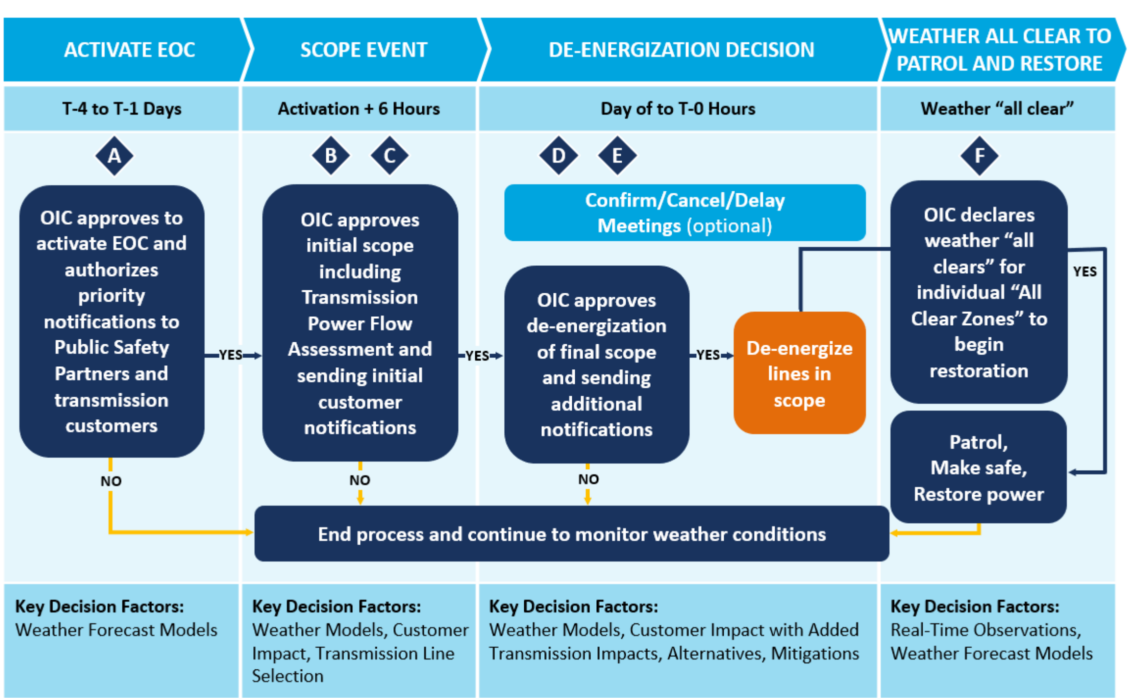
FIGURE PG&E-8.4.2-4:
WILDFIRE ACTIVATION, RESPONSE, RECOVERY, AND RESTORATION PROCESS



Operational flow diagram for PSPS events

Key process decisions for PG&E PSPS activation, de-energization and restoration of service are show in Figure PGE-8.4.2-5 below.

FIGURE PG&E 8.4.2-5:
PG&E PSPS KEY PROCESS DECISIONS



Key Personnel, Qualifications and Training

Key Personnel

PG&E's Director of EP&R Strategy and Execution (SE) 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.

- 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.

- Liaison Officer and Assistant Liaison Officer – Responsible for leading the team that serves as the primary contact for external partners such as representatives of local, tribal, state, and federal governments.

- Customer Strategy Officer: Responsible for sending customer notifications before, during and after an event, prioritizing notifications to critical public safety-related facilities and Medical Baseline customers among others. The Customer Strategy officer is also responsible for identifying and opening Customer Resource Centers to support impacted customers.

- Public Information Officer (PIO)/ Assistant PIO – Responsible for providing strategic communications counsel to the EOC commander.

For additional information on key PG&E EOC personnel roles and responsibilities, please see Section 8.4.2.2.1 Personnel Qualifications. Teams for other PG&E emergency centers and facilities (e.g., Control Centers, Support and Coordination Centers) are found in PG&E functional area plans and CERP functional annexes.

Day shift and night shift teams may be activated at the discretion of the EOC Commander.

Qualifications

PG&E maintains rigorous qualification standards for wildfire and PSPS emergency personnel who must be trained on the basics of Incident Command Systems to be certified to work in one of our Emergency Operation Centers. Depending on their level of responsibility within the EOC, personnel also receive expanded and specialized training to build upon their basic learning. For more details on qualifications, focusing on specific roles, incident types, and responsibilities, please refer to Section 8.4.2.2.1 Personnel Qualifications.

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.

For more information on our training curriculum, please see Table PG&E-8.4.2-2 in Appendix F which shows the different training courses 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;
- G-191 – ICS/EOC Interface;
- G626 – EOC Action Planning;
- ICS-300 - Intermediate Incident Command System for Expanding Incidents;

- ICS-400 – Advanced ICS for Command and General Staff;
- IS-702 PIO - National Incident Management System (NIMS) Public Information Systems;
- ICS-402 - NIMS Overview for Senior Officials;
- IS-230d – Fundamentals of Emergency Management; and
- G-611- EOC Section/Position Specific Training.

Resource Planning and Allocation

EOC and Field Incident Commanders (IC) have the authority to make decisions and commit resources consistent with the scale of the emergency and PG&E's delegation of authority. The EOC develops and executes a resource mobilization strategy considering resource availability in coordination with Operations, the base resource plan, and anticipated staffing requirements. The team uses a resource tracker to build staffing plans and signal the need for additional resources. As part of the EOC On-call Teams program, EP&R SE maintains a list of predesignated qualified Incident Commanders. Consistent with PG&E's delegations of authority, the Director of EP&R SE may activate the EOC. Predesignated ICs from different functional areas have been assigned to on-call teams and may serve in any type of emergency at the discretion of the Director of EP&R SE.

Drills, Simulations, and TTXs

From January 1, 2022, to December 31, 2022, PG&E's Public Safety Specialists (PSS) team[155] conducted a series of First Responder Workshops with local public safety agencies. A total of 2,879 representatives, from 187 local public safety agencies attended.

For more details on PG&E's training programs, including the use of drills, simulations, and TTXs, please see Section 8.4.2.3.

Coordination and Collaboration With Public Safety Partners (e.g., Emergency Planning, Interoperable Communications)

PG&E engages in extensive outreach and engagement with our public safety partners. For more details on our collaboration with these entities, please see Section 8.4.3.1 and Section 8.4.3.2.

Notification and Communication with Customers During and After a Wildfire or PSPS Event

PG&E's strategy for communicating with the customers regarding wildfires and PSPS events is described in the CERP and the Emergency Communications Annex to the

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[155] PG&E PSS personnel serve as contacts for city and county representatives at outreach meetings held in accordance with Pub. Util. Code, § 768.6.

CERP. In an emergency, primary points of contact for customers can be found on the pge.com website in the PG&E Customer Service Center Brochure.

Additionally, there are two Contact Service Centers open to help customers. These centers continue to be the primary avenue customers use to report emergencies. Information on how to reach these centers can be found by visiting the Contact Us page on the pge.com website.

Contact Service Centers also provide multilingual, telephonic services, including California Relay Service and/or Telecommunications Device for the Deaf/Teletypewriter (TDD/TTY) for customers who are speech and hearing-impaired. These centers also respond to email contacts that may be made through the Company website.

For more information on PG&E's outreach to stakeholders see Section 8.4.4.1.

Improvements/Updates Made Since the Last WMP Submission

PG&E's use of multiple, standing day and night EOC rosters has improved service reliability and safety by clarifying roles and responsibilities for separate but staggered PSPS events. Standing rosters is considered a best practice approach.

PG&E's EP&R staff, EOC Command, and General staff can, when needed, operate in a virtual environment. This approach is efficient because it reduces commute times and physical facility footprints, improves real-time communications, and enables leaner EOC operations.

PG&E has implemented the PSPS Situational Intelligence Platform (PSIP). This platform is built on the Palantir Foundry system. The PSIP is connected to more than 50 source systems containing billions of records relevant to asset health analytics. It is PG&E's central PSPS decision-making, reporting, and communications platform. The PSIP is described in more detail in the CERP PSPS Annex.

PG&E has continued to reduce the size and duration of PSPS events. This is an indicator of increased operational maturity, flexibility, and system resilience.

Gaps and Limitations

PG&E hosted the 2022 PSPS and Wildfire Full-Scale Exercise (FSE) beginning with readiness posture in June 2022. The FSE simulated R5-Plus extreme weather wildfire risk conditions designed to test our ability to prepare for, respond to, and recover from a PSPS event, concurrent with an ignition of a rapidly expanding Wildfire. Exercise operations were carried out per the CERP, PSPS Annex, Wildfire Annex, and other PG&E functional area plans. Gaps, limitations, and remedial action strategies coming out of that exercise are listed in Table 8-37, below.

TABLE 8-37:
KEY GAPS AND LIMITATIONS IN INTEGRATING WILDFIRE AND PSPS SPECIFIC STRATEGIES INTO EMERGENCY PLAN

Gap or Limitation Subject	Remedial Brief Description	Remedial Action Plan
Planning	Practiced routinely and effectively during gas asset “dig in” accidents and exercises, PG&E is working to further apply California SEMS incident management and support principles to integrate internal and external EOC level wildfire response and PSPS event management operations. Use of SEMS optimizes command, control, and coordination externally and internally across PG&E functional areas.	For 2023, PG&E will work to achieve Type III California Specialized Training Institute SEMS credentialling for all EOC Command and General staff personnel.
Operational Coordination and Communication	Although effective, PG&E’s PSPS Communications Coordinator Comms Huddle process requires further refinement in the areas of sequencing materials, roles, problem solving, and overall operational communications clarity.	In 2023, PG&E will pilot a new All-hazards Incident Management Dashboard, including four common operating picture information elements: assets, outages, incident command, and resources
Public Information and Warning	2022 EOC exercises activities evidenced a lack of standardized Joint Information System (JIS) use across all EOC-level incident and event types. Consistent with the California SEMS and applicable to public and private sector organizations, the JIS provides standardized process, procedures, and tools that facilitate communication to the public, incident personnel, the media, and other stakeholders.	The JIS integrates incident information and public affairs into a unified organization to provide consistent, coordinated, accurate, accessible, timely and complete information to the public and stakeholders during incident and event operations. In 2023, PG&E will evaluate standardized, formalized use of the JIS across all EOC-level incident and event types.
Critical Resources	2022 EOC exercises activities evidenced ineffective resource allocation communications regarding the allocation and staging of Mutual Assistance resources.	Use of the ICS-204 Assignment List process enables the expansion and contraction of incident resource assignments in a scalable, predictable manner, thus ensuring resource availability in relation to need. In 2023, PG&E will train incident command and support Resource Unit personnel on the use of ICS-204 Assignment List and related iterative ICS-215 operational planning worksheet process.

8.4.2.2 Key Personnel, Qualifications, and Training

In this section, the electrical corporation must provide an overview of the key personnel constituting its emergency planning, preparedness, response, and recovery team(s) for wildfire and PSPS events. This includes identifying key roles and responsibilities, personnel resource planning (internal and external staffing needs), personnel qualifications, and required training programs.

To meet the challenges of wildfire and PSPS-related events, PG&E provides ongoing, robust, and comprehensive training programs for our personnel and external contractors. This includes identifying key roles and responsibilities, personnel resource planning, personnel qualifications, and required training programs. For more details, please see Section 8.4.2.2.1, Section 8.4.2.2.2, and Section 8.4.2.2.3.

8.4.2.2.1 Personnel Qualifications

The electrical corporation must report on the various roles, responsibilities, and qualifications of electrical corporation and contract personnel tasked with wildfire emergency preparedness planning, preparedness, response, and recovery, and those tasked for PSPS-related events. This may include representatives from administration, information technology (IT), human resources, communications, electrical operations, facilities, and any other mission-critical units in the electrical corporation. As part of this section, the electrical corporation must provide a brief narrative on how it determined its personnel resource planning for various key roles and responsibilities. The narrative must be no more than two to four pages.

Table 8-38 provides an example of the minimum level of content and detail required.

Scalable by design, PG&E staffs our EOC for wildfires and other all-hazard incidents using the standard SEMS ICS Command and General Staff incident management staffing pattern with representatives from multiple organizations: Business Finance; Information Technology; Human Resources; Gas and Electric Operations; Supply Chain and Materials; Customer and Communications; Government Relations; Safety; Meteorology; and EP&R.

The key driver for PG&E emergency personnel resource planning is the ICS founded on Firefighting Resources of California Organized for Potential Emergencies (FIRESCOPE). The ICS is a standardized, hierarchical incident/event management structure that allows for cooperative emergency response without compromising decision authority at the local level. The ICS structure is built around five major management activities or Command and General Staff functional areas.

- Command: Includes Incident Commander (IC), Safety, Liaison, and Communication. It sets priorities and objectives and is responsible for overall control of the incident.

- Operations: Accountable for all tactical operations necessary to carry out the incident or event action plan.

- Planning: Responsible for the collection, evaluation, and distribution of information regarding incident development and the availability of resources.

- Logistics: Responsible for providing the necessary facilities, services, and materials to meet incident or event needs.

- Finance/Administration: Responsible for monitoring and documenting all costs while providing the necessary financial support related to the incident.

PG&E uses the ICS as a basis for emergency personnel resource planning roles, responsibilities, and qualifications.

For a PSPS event, the EOC organization consists of the standard ICS Command and General Staff positions as outlined in the CERP and includes the use of an additional Intelligence and Investigation Section, which is established within the General Staff organization. Along with the standard ICS roles, PG&E's PSPS processes includes the use of several PSPS specific EOC functional roles listed below:

- Officer-in-Charge (OIC);
- Deputy Planning Section PSPS Chief;
- PSPS Technical Unit Leader;
- PSPS Technical Specialist;
- PSPS Distribution Asset Health Specialist (DAHS);
- PSPS Transmission Asset Health Specialist (TAHS);
- PSPS Portal Unit Leader;
- PSPS Portal Unit Support;
- PSPS Process Unit Leader;
- PSPS Recorder;
- PSPS Communications Coordinator;
- PSPS Risk Analyst;
- Digital Strategy Lead;
- Digital Strategy Publisher;
- Digital Strategy Assistant;
- Primary Voltage Generation Division Lead; and

- Secondary Voltage Generation Division Lead.

The OIC is a role specific to PSPS events and was created to engage higher-level management accountability in the decision given the magnitude and impact of PSPS, while also enabling rapid decision-making during a real-time PSPS event. The OIC receives situational awareness from the Command Staff and General Staff of PG&E's EOC, including from the Meteorology, Planning, and Customer Sections.

For more information on key PG&E EOC personnel roles, responsibilities, and qualifications, please see Table 8-38, below.

TABLE 8-38:
EMERGENCY PREPAREDNESS STAFFING AND QUALIFICATIONS

Role	Incident Type	Responsibilities	Qualifications	# of Dedicated Staff Required	# of Dedicated Staff Provided	# of Contract Workers Required	# of Contract Workers Provided
EOC Commander/ Deputy EOC Commander	Wildfires PSPS	The EOC IC is responsible for the overall command of the incident/event. This includes: • Ensuring the safety of all employees involved; • Initiating, and approving the IAP; and • Acting as a liaison with agency executives, governing boards, and other organizations. In addition, during a PSPS the on-call EOC Commander (EC) is responsible for: • Coordinating readiness of activities related to Readiness Posture; • Advising OIC on decisions; • Reviewing OIC decision records and documentation; and • Executing decisions made by OIC.	• ICS 100 • ICS-200 • ICS-700 • ICS-800 • SEMS G606 • IS-368 • G-775 • G-191 • G-626 • ICS 300 • ICS 400 • IS230d • G-611 M	16	14	0	0

TABLE 8-38:
EMERGENCY PREPAREDNESS STAFFING AND QUALIFICATIONS
(CONTINUED)

Role	Incident Type	Responsibilities	Qualifications	# of Dedicated Staff Required	# of Dedicated Staff Provided	# of Contract Workers Required	# of Contract Workers Provided
Liaison Officer/ Assistant Liaison Officer	Wildfires PSPS	The Liaison Officer (LNO) is responsible for: • Leading the team that serves as the primary contact for representatives of local, tribal, state, and federal governments. • Participating in weather briefings, planning meetings, command and general staff meetings, and OIC decision meetings. • Informing the LNO team when key decisions are made or are expected. The LNO makes real-time decisions on behalf of the LNO Team. • The LNO oversees PSPS event notifications and interactions with external partners such as tribes, cities, counties, state, and federal agencies. Additional responsibilities include: • Coordinating with Tribes, cities, counties, and other agencies to help ensure PG&E has the latest contact information for each agency. • Working with tribal, city, county, and state contacts during PSPS events to coordinate and align operations and response. • Sending notifications (before, during, and after a PSPS event) to Cal OES, the CPUC, tribes, cities, counties, first responders, and other external stakeholders. • Responding to and tracking inquiries from external stakeholders.	• ICS 100 • ICS-200 • ICS-700 • ICS-800 • SEMS G606 • IS-368 • G-775 • G-191 • G-626 • ICS 300 • IS230d • G-611 M	16	22	0	0

**TABLE 8-38:
EMERGENCY PREPAREDNESS STAFFING AND QUALIFICATIONS
(CONTINUED)**

Role	Incident Type	Responsibilities	Qualifications	# of Dedicated Staff Required	# of Dedicated Staff Provided	# of Contract Workers Required	# of Contract Workers Provided
		• Facilitating and managing a once-daily State Executive Briefing and a once-daily Cooperator call for county, city, utility, and emergency management partners for external situational awareness. • Supporting requests and serving as single point of contact from third-party representatives to embed in PG&E's EOC					
Customer Strategy Officer	Wildfires PSPS	• Sending customer notifications before, at de-energization, during, and after an event to all customers—initially prioritizing notifications to critical public safety-related facilities and transmission customers, followed by notifications to Medical Baseline customers and to general customers in the PSPS scope. • Identifying and opening Community Resource Centers (CRC) to support impacted customers. Coordinating with CRC leads to gather real-time local intelligence for Customer Service Office/Logistics to respond; accordingly, managing customer escalations; and aggregating daily reports from each CRC for timely reporting. • Coordinating with local Independent Living Centers (ILC) and Community-Based Organizations (CBO) to support Access and Functional Needs (AFN) customers in attendance as appropriate.	• ICS 100 • ICS-200 • ICS-700 • ICS-800 • SEMS G606 • IS-368 • G-775 • G-191 • G-626 • ICS 300 • IS230d • G-611 M	8	10	0	0

TABLE 8-38:
EMERGENCY PREPAREDNESS STAFFING AND QUALIFICATIONS
(CONTINUED)

Role	Incident Type	Responsibilities	Qualifications	# of Dedicated Staff Required	# of Dedicated Staff Provided	# of Contract Workers Required	# of Contract Workers Provided
		• Facilitating doorbell rings to notify Medical Baseline (MBL) customers and Self-Identified Vulnerable customers that were not successfully contacted through initial automated notifications (i.e., e-mails, phone calls, and text messages). • Coordinating with Community Choice Aggregators (CCA) relations teams to engage with potentially impacted CCAs during event. • Managing customer escalations including commercial critical customers and those within the AFN population (i.e., MBL, Life Support, Self-Identified Vulnerable). • Coordinating with the Customer Contact Emergency Coordination Center to provide event intelligence for staffing and communication needs. • Working with OECs to gather real-time local intelligence to fully inform IC and identifying escalations, challenges, and events that could impact the scope of the PSPS event. • Communicating with critical public safety-related customers, addressing customer escalations, and providing intelligence to the OIC for consideration when determining de-energization scope and prioritizing restoration. • Coordinating with the Temporary Generation Branch team on prioritization of customer requests for temporary back-up power during an event. • Coordinating with Billing Operations and Credit, Demand Response teams and additional internal partners regarding customer impacts. • Coordinating with Electric Operations on Estimated Time of Restoration (ETOR) notifications and restoration priorities.					

TABLE 8-38:
EMERGENCY PREPAREDNESS STAFFING AND QUALIFICATIONS
(CONTINUED)

Role	Incident Type	Responsibilities	Qualifications	# of Dedicated Staff Required	# of Dedicated Staff Provided	# of Contract Workers Required	# of Contract Workers Provided
Public Information Officer (PIO)/ Assistant PIO	Wildfires PSPS	The PIO's role is to provide strategic communications counsel to the EOC Commander. The PIO's responsibilities during a PSPS event include: • Developing main narrative for talking points. • Developing and implementing communications strategy to ensure "one voice" communications. • Coordinating with Customer team, Liaison, and any other Lines of Business (LOB) stakeholders on communication materials. • Coordinating emergency communication activities with other agencies, media, customers and others through verbal replies, on-camera interviews, written statements, press releases, and social media. • Providing early warning of a potential PSPS event when possible, using a combination of direct communication and traditional and social media. • Informing employees through internal communications about the PSPS event. • Responding to real-time media requests for information, interviews, and status reports. • Conducting press conferences and managing press questions and queries.	• ICS 100 • ICS-200 • ICS-700 • ICS-800 • SEMS G606 • IS-368 • G-775 • G-191 • G-626 • ICS 300 • IS230d • G-611 M • IS 702	16	26	0	0

TABLE 8-38:
EMERGENCY PREPAREDNESS STAFFING AND QUALIFICATIONS
(CONTINUED)

Role	Incident Type	Responsibilities	Qualifications	# of Dedicated Staff Required	# of Dedicated Staff Provided	# of Contract Workers Required	# of Contract Workers Provided
Safety Officer/ Assistant Safety Officer	Wildfires PSPS	The Safety Officer's responsibilities during a PSPS event include: • Preparing safety messaging on potential hazards for line/office personnel, substation personnel, Field Observers, and contractors as well as disseminating safety messages to "EO EOC out" mailbox. • Confirming Safety staff availability for EOC field support and availability of protective equipment and supplies as appropriate. • Finalizing Field Safety Specialist deployment plans based on Operational needs, operations crew deployment plans • Accompanying Field Observers, crews, and patrols to support safe working and driving conditions as well as safe restoration activities as appropriate. • Incorporating field observations into safety messaging.	• ICS 100 • ICS-200 • ICS-700 • ICS-800 • SEMS G606 • IS-368 • G-775 • G-191 • G-626 • ICS 300 • IS230d • G-611 M	16	17	0	0

TABLE 8-38:
EMERGENCY PREPAREDNESS STAFFING AND QUALIFICATIONS
(CONTINUED)

Role	Incident Type	Responsibilities	Qualifications	# of Dedicated Staff Required	# of Dedicated Staff Provided	# of Contract Workers Required	# of Contract Workers Provided
Operations Section Chief/ Deputy Operations Section Chief	Wildfires PSPS	The Operations Section Chief implements the de-energization and restoration strategy for PSPS events and achieves the incident objectives set by EOC Commander and communicated in the IAPs. The Operations Section Chief ensures coordination with other EOC sections and emergency centers (such as REC and OEC).	• ICS 100 • ICS-200 • ICS-700 • ICS-800 • SEMS G606 • IS-368 • G-775 • G-191 • G-626 • ICS 300 • IS230d • G-611 O	16	15	0	0
Planning Section Chief/ Deputy Planning Section Chief/ PSPS Deputy Planning Section Chief	Wildfires PSPS	• The Planning Section Chief is responsible for directing Planning Section staff and developing their respective documentation. They also focus on leading/ participating in meetings, representing the Planning Section perspective in OIC Decision meetings, and reviewing all Planning-developed external materials. • For PSPS, the Planning Section Chief has two deputies: a Deputy Planning Section Chief and a PSPS Deputy Planning Section Chief. These deputies work with staff to confirm activities are being performed according to procedures. They work together closely, dividing leadership responsibilities in alignment with ICS. • The Deputy Planning Chief leads the standard ICS Units (Documentation Unit, Situation Unit, Resource Unit, Resource Management Unit and Demobilization Unit).	• ICS 100 • ICS-200 • ICS-700 • ICS-800 • SEMS G606 • IS-368 • G-775 • G-191 • G-626 • ICS 300	24	21	0	0

		• The Deputy Planning Chief leads the standard ICS Units (Documentation Unit, Situation Unit, Resource Unit, Resource Management Unit and Demobilization Unit). • The PSPS Deputy Planning Chief leads the group of specific PSPS units established within the Planning Section (PSPS Technical Unit Leader, PSPS DAHS, PSPS TAHS, PSPS Portal Unit Leader, PSPS Process Unit Leader, and the PSPS Risk Analyst). • The Planning Section is responsible for collecting, evaluating, and displaying event intelligence and information, and is the source of all event impact data. Updates are communicated broadly through the EOC. Additional responsibilities include: • Preparing and maintaining event documentation including the Situation Report, Cal OES Notification Form, and event Playbooks. • Documenting circuits potentially in de-energization scope, customers potentially in de-energization scope, and customers proactively de-energized by PSPS event. • Developing PSPS event impact maps in various formats to be used by Public Safety Partners and critical public safety-related customers. • Developing long-range resource, contingency, and demobilization plans.	• IS230d • G-611 P					

TABLE 8-38:
EMERGENCY PREPAREDNESS STAFFING AND QUALIFICATIONS
(CONTINUED)

Role	Incident Type	Responsibilities	Qualifications	# of Dedicated Staff Required	# of Dedicated Staff Provided	# of Contract Workers Required	# of Contract Workers Provided
Logistic Section Chief/ Deputy Logistics Section Chief	Wildfires, PSPS	The Logistics Section Chief oversees the Logistics Section which consists of the Deputy Logistics Section Chief, the Service and Support branches, the Logistics Reporting Unit, and may include the Materials and Transportation Coordination Center depending on the scope and nature of the emergency. The Logistics Section secures resources, supplies, food, lodging, vehicles and equipment rentals, fuel, security, and medical services, as well as maintains equipment for incident personnel	• ICS 100 • ICS-200 • ICS-700 • ICS-800 • SEMS G606 • IS-368 • G-775 • G-191 • G-626 • ICS 300 • IS230d • G-611 L	16	16	0	0
Finance & Admin Section Chief/ Deputy F&A Chief	Wildfires PSPS	Human Resources (HR) and Finance coworkers are assigned to Finance and Administration Section emergency roles HR and Finance coworkers share the assignment responsibility for the Section Chief and Deputy Section Chief emergency roles to ensure HR and Finance subject matter expertise is included at this leadership level. The Finance and Administration (F&A) Section Chief is an EOC General Staff emergency role. During all-hazard response incidents, the F&A Section Chief is responsible for finance and human resource support. The Section Chief and Section Deputy Chief activate and perform the consolidated section leadership and administrative actions.	• ICS 100 • ICS-200 • ICS-700 • ICS-800 • SEMS G606 • IS-368 • G-775 • G-191 • G-626 • ICS 300 • IS230d • G-611 F	16	23	0	0

TABLE 8-38:
EMERGENCY PREPAREDNESS STAFFING AND QUALIFICATIONS
(CONTINUED)

Role	Incident Type	Responsibilities	Qualifications	# of Dedicated Staff Required	# of Dedicated Staff Provided	# of Contract Workers Required	# of Contract Workers Provided
PSPS Intel & Investigation Section Chief	Wildfires PSPS	The Intelligence and Investigation (I&I) Section Chief, in conjunction with the PSPS I&I Section Process Manager, ensures compliance with the regulatory requirements that PG&E reports on any wind-related damage or hazards sustained by PG&E facilities during a PSPS event including Resolution ESRB-8, Ordering Paragraph 1 of D.19-05-042 (Phase 1), and Ordering Paragraph 1 of D.20-05-051 (Phase 2) in addition to investigation of any other incidents arising out of the PSPS event (e.g., Fire/ignition). The I&I Sections responsibilities during a PSPS event include: • Maintaining the PSPS Damage Hazard Form via Inspect App and/or paper form to record damages and hazards observed in the post de-energization patrol; • Receiving and aggregating the reports of damages and hazards (including photos) into a master table; • Quality-control review of the damages and hazards documentation to verify they are PSPS qualified and reportable; • Managing a PSPS Damage/Hazard dashboard to provide situational awareness to the damages/hazards identified during patrol, ensuring the dashboard is actionable by stakeholders; • Drafting the language for the damage documentation section of the CPUC Deenergization Post-Event Report; and • Providing validated and structured damage and hazard data to satisfy data requests from external and internal stakeholders.	• ICS 100 • ICS-200 • ICS-700 • ICS-800 • SEMS G606 • IS-368 • G-775 • G-191 • G-626 • ICS 300 • IS230d • G-611 P	8	8	0	0

For more information on our training curriculum, please see Table PG&E-8.4.2-2 in Appendix F.

8.4.2.2.2 Personnel Training

The electrical corporation must report on its internal personnel training program(s) for wildfire and PSPS emergency events. This training must include, at a minimum, training on relevant policies, practices, and procedures before, during, and after a wildfire or PSPS event. The reporting must include, at a minimum:

- *The name of each training program;*
- *A brief narrative on the purpose and scope of each program;*
- *The type of training method;*
- *The schedule and frequency of training programs;*
- *The percentage of staff who have completed the most current training program; and*
- *How the electrical corporation tracks who has completed the training programs.*

Table 8-39 provides an example of the minimum acceptable level of information.

Personnel Training Overview

PG&E has multifaceted training programs for staff that support outages related to wildfires and PSPS. These include:

- EP&R Emergency Preparedness Training CERP;
- PSPS-Specific Training Program; and
- PSPS Field Personnel Training.

EP&R Emergency Preparedness Training and CERP

The EP&R organization sets priorities for training and exercises considering PG&E's priorities, legal and other requirements, stakeholder feedback, threats, hazards and risk assessment data, and our ability to perform and deliver core capabilities during training exercises and actual events.

PSPS Specific Training Program

Personnel who respond to PSPS outages are required to take PSPS specific training. This includes high-level, overview courses and role-specific trainings that focus on the responsibilities that staff assume during PSPS outages.

PSPS Field Personnel Training

In 2022, PG&E updated PSPS Procedure PSPS-1000P-01 ("Public Safety Power Shutoff for Electric Transmission and Distribution") to improve operational response based on feedback/improvements from 2021 PSPS Events.

Table 8-39 below lists PG&E's training programs related to PSPS and wildfires, the purpose of each program, the training method, frequency, the position or title of personnel required to take the training, and the number of PG&E team members who have taken each course.

TABLE 8-39:
PG&E'S PERSONNEL TRAINING PROGRAMS FOR WILDFIRE AND PSPS EVENTS

Training Topic	Purpose and Scope	Training Method	Training Frequency	Position or Title of Personnel Required to Take Training	# Personnel Requiring Training	# Personnel Provided with Training	Form of Verification or Reference
EP&R Emergency Preparedness Training Program	The purpose of this training is to give employees with an emergency role the tools to deliver the right response during an activation. The training is aligned to California SEMS and FEMA standards.	Online web-based training and virtual instructor lead courses	One time	EOC staff	756	655	Training certificates on file and training transcripts
CERP Training	This training provides an overview of the CERP, the blueprint for Company policies and strategies for emergency response	Online Web Based Training	Annually	EOC Staff	828	598 completed this year 217 on track to meet annual completion requirement	Training Transcripts
PSPS Specific Training Program	Prepare EOC personnel on how to respond during a PSPS activation.	Online Web Based Training courses and in-person training, including PPT, exercises and activities, Performance Support tools, Knowledge and Skill Checks, Drills	Annually	Planning Section personnel with PSPS-specific duties	76	66	Training Transcripts

**TABLE 8-39:
PG&E'S PERSONNEL TRAINING PROGRAMS FOR WILDFIRE AND PSPS EVENTS
(CONTINUED)**

Training Topic	Purpose and Scope	Training Method	Training Frequency	Position or Title of Personnel Required to Take Training	# Personnel Requiring Training	# Personnel Provided with Training	Form of Verification or Reference
PSPS Restoration Process	To ensure compliance with PSPS-1000P-01 (Public Safety Power Shutoff for Electric Transmission and Distribution)	Online courses	Annually (12-month rolling requirement per person)	Division OEC Personnel	1,632 (2022)	1,607 (2022)[a]	Learning Services group (PSPS-0001 WBT PSPS Restoration Process
PSPS Execution for Distribution Control Center (DCC) Operators	To ensure compliance with PSPS-1000P-01 (Public Safety Power Shutoff for Electric Transmission and Distribution)	Online courses	Annually (12-month rolling requirement per person)	Distribution Control Center Operators	126 (2022)	125 (2022)[a]	Learning Services group (PSPS-0002 WBT PSPS Execution for DCC Operators)

(a) The discrepancy between required and completed training is because trainings being completed on a 12-month rolling basis. All personnel requiring this training will complete the training within their 12-month time period.

8.4.2.2.3 External Contractor Training

The electrical corporation must report on its external contractor training program(s) for wildfire and PSPS emergency events. This training must include, at a minimum, training on relevant policies, practices, and procedures before, during, and after a wildfire or PSPS event. The reporting must include, at a minimum:

- *The name of each training program;*
- *A brief narrative on the purpose and scope of each program;*
- *The type of training method;*
- *The schedule and frequency of training programs;*
- *The percentage of contractors who have completed the most current training program; and*
- *How the electrical corporation tracks who has completed the training programs.*
- *Table 8-40 provides an example of the minimum acceptable level of information.*

PG&E does not use contractors in the EOC, therefore, there are no contractors who receive the EOC training described in the previous two sections. PG&E does use contractors for Patrol and for Wildfire and PSPS damage restoration. These field contractors receive training in wildfire ignition prevention. Please see Table 8-40 below.

TABLE PG&E-8-40:
CONTRACTOR TRAINING PROGRAM

Training Topic	Purpose and Scope	Training Method	Training Frequency	Position or Title of Personnel Required to Take Training	# Contractors Requiring Training	# Contractors Completed Training	Form of Verification or Reference
TD-1464S contractor training is conducted through SAFE 1503 WBT Fire Danger Precautions course	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 and contract partners performing work in hazardous fire areas by educating them on how to take the proper precautions and implement fire mitigation measures. The course covers the Fire Potential Index daily forecast; how to consult the Wildfire Mitigation Matrix & the Wildfire Risk Checklist to apply mitigation strategies according to the FPI rating; how to prepare for work by implementing required mitigation strategies and adjust if FPI ratings or weather conditions change; and how to use fire mitigation tools.	Contract partners complete this course via the ISNetworld portal as a web-based training course.	This training is profiled to the target audience as mandatory, generally to be completed annually between January 1 and April 1	All PG&E employees and contract partners performing PG&E work which may result in a spark, fire, or flame on or near any forest- brush-, or grass-covered lands are required to take this training.	Due to a database maintenance issue from a third-party provider, we are currently unable to produce this information in an accurate manner. However, we are working with our third-party contractor to refine their database tracking methodology. Our standard requires new hires to complete the training within 90 days of the assignment date, and for existing contractors to complete the training annually between January 01 and April 01. We have created the Contractor-Specific Training Improvements Project Team to help enforce this policy. Their efforts will result in the development and publication of related guidance document(s).	11,036	We track our contractor training through ISNetworld

8.4.2.3 Drills, Simulations, and Tabletop Exercises

Discussion-based and operational-based exercises enhance knowledge of plans, allow personnel to improve their own performance, and identify opportunities to improve capabilities to respond to real wildfire emergency events and PSPS events. Exercises also provide a method to evaluate an electrical corporation's emergency preparedness plan and identify planning and/or procedural deficiencies.

Throughout our service territory, we conduct PSPS field exercises to prepare utility personnel to restore services after the event has ended. Prior to the field exercises, personnel complete two courses (PSPS-0001WBT PSPS Restoration Process and PSPS-0002WBT PSPS Execution for Distribution Control Centers Operators) to ensure compliance with PSPS-1000P-01 (Public Safety Power Shutoff for Electric Transmission and Distribution) which provides focused alignment with the overall PSPS efforts.

These PSPS courses and field exercises are conducted for all PG&E divisions in the HFTD and HFRA areas, with the focus on safe and efficient service restoration following emergencies.

8.4.2.3.1 Internal Exercises

The electrical corporation must report on its program(s) for conducting internal discussion- based and operations-based exercises for both wildfire and PSPS emergency events. This must include, at a minimum:

- *The types of discussion-based exercises (e.g., seminars, workshops, TTXs, games) and operations-based exercises (e.g., drills, Functional Exercises (FE), FSEs);*
- *The purpose of the exercises;*
- *The schedule and frequency of exercise programs;*
- *The percentage of staff who have completed/participated in exercises; and*
- *How the electrical corporation tracks who has completed the exercises.*

Table 8-41 provides an example of the minimum acceptable level of information.

Utility Initiative Tracking ID: EP-01

PG&E's EP&R Strategy and Execution team is responsible for developing and facilitating corporate level exercises.

These emergency preparedness exercises allow participants to practice the duties, tasks, and operations they are expected to perform in a real emergency. They are adapted from the HSEEP to serve a utility and test emergency plans on an ongoing basis at least once per calendar year.

The common, core capabilities evaluated for every exercise are:

- Situational Assessment;
- Operational Communications;
- Operational Coordination;
- Public Information and Warning;
- Logistics and Supply Chain Management;
- Planning; and
- Safety.

The Director of EP&R Strategy and Execution is responsible for ensuring that exercises mandated by regulatory agencies are performed at least annually, or more frequently if required, to meet regulatory timelines.

Exercise planners from each functional area develop their portion of the exercise following all planning guidelines and timelines. Exercise planners and support staff participate in the full-scale or FE as a controller, evaluator, or a simulator. In the TTXs, the planner will serve to help develop the questions and evaluate their player's response for their functional area.

PG&E's CERP and related annex exercises are based on emergency management program priorities and test the specific operational components included in the CERP and annexes.

PG&E's PSPS FSE includes division-level field exercises which consist of physical field patrols (both ground and air) on pre-determined circuits.

PG&E's EP&R SE Exercise Team plans, coordinates, and conducts emergency preparedness exercises that are consistent with the HSEEP, the California SEMS, and the NIMS methodologies. They include:

- Seminars;
- Workshops;
- TTXs;
- Games;
- Drills;
- FE; and

- FSEs.

PG&E's Company-wide, multi-year training and exercise program is described in the EP&R MYTEP. PG&E conducted multiple wildfire and PSPS exercises in 2022. For more details see Table PG&E-8.4.2-3 in Appendix F.

Division-Level Exercises

PG&E provided an annual Division-Level field exercise platform for participating field employees using updated 2022 restoration protocols.

Division-Level field exercises were conducted in the 18 PG&E divisions that are in the HTFD and/or HFRA areas.

- Day 1: PSPS protocols/procedure refresher regarding execution criteria, scoping, de-energization, segmenting (preparation for step restoration), communication alignment and collateral procurement (segment guides, PSPS maps, etc.).
- Day 2: Physical field patrols (both air and ground of pre-determined circuits) and simulated re-energization using circuit-based hierarchy supporting step restoration methodology following the declared end of the weather event. Participants included both field level and distribution control center personnel.

Participation Tracking

Participation in the field level exercises was documented through PG&E Learning Services, course code PSPS-0320. The total number of staff who completed/participated in other exercises is tracked via a participant roster and a check in check out system.

For more details on internal drills, simulations, and TTXs, please see Table 8-41, below:

TABLE 8-41:
INTERNAL DRILL, SIMULATION, AND TABLETOP EXERCISE PROGRAM

Category	Exercise Title and Type	Purpose	Exercise Freq.	Position or Title of Personnel Required to Participate	# Personnel Participation	# Personnel Participation Completed[(a)]	Form of Verification or Reference
Discussion Based	Wildfire Response Seminar	Provide an overview of PG&E's plans, procedures, and tools used to respond to and mitigate the effects of a Wildfire.	Annually	• EOC team members • Emergency Field Operations • Electric Distribution Emergency Center (EDEC) • Electric Transmission Emergency Center (ETEC) • Gas Emergency Center (GEC) staff • PSS • PSPS Project Management Office (PMO)	0[(b)]	205	Attendance record and Outlook invitation
Discussion Based	PSPS Response Seminar	Understand the PSPS Program and the history of the PSPS Regulation requirements and how we are making these required improvements. Explain the PSPS Process at a "High Level." Understand the importance of Meteorology's role before and during a PSPS event. Learn how "Scoping" comes into play and how it sets the tone for the event. Understand the roles and responsibilities of PGE's other LOBs and more specifically how each program Communicates, Prepares, Responds, and Recovers from an incident.	Annually	• EOC team members • Emergency Field Operations • EDEC • ETEC • GEC staff • PSS • PSPS PMO	0	232[(a)]	Attendance record and Outlook invitation

TABLE 8-41:
INTERNAL DRILL, SIMULATION, AND TABLETOP EXERCISE PROGRAM
(CONTINUED)

Category	Exercise Title and Type	Purpose	Exercise Freq.	Position or Title of Personnel Required to Participate	# Personnel Participation	# Personnel Participation Completed[(a)]	Form of Verification or Reference
Discussion Based	PSPS event TTX	The TTX is aimed at discussing the various stages of the PSPS Procedural Flow (ProFlow) process with internal LOBs and External Agencies. PSPS TTX simulates R5-Plus weather conditions to test PG&E's ability to prepare for, respond to, and recover from a PSPS event. TTX aims to help PG&E response teams apply the PSPS specific knowledge provided by the training series in a realistic scenario. The TTX requires participants to review and use the CERP, PSPS Annex, and other LOB-specific plans to answer discussion-based scenario questions.	Annually	• Electric Distribution • Transmission Grid Operations • Electric Transmission • Electric Field Operations • Information Technology • Electric Incident Investigations • Corporate Safety • Corporate Security • Corporate Real Estate Strategy and Services (CRESS) • Aviation Services • Corporate Affairs • Supply Chain Customer Care • Human Resources • Marketing & Communications • PSPS Technology/Operations • Meteorology • Public Affairs • Temporary Generation • HAWC • Finance • Supply Chain • Vegetation Management • Power Generation	54	97	Exercise situation manual, attendance records, and After-Action Report

TABLE 8-41:
INTERNAL DRILL, SIMULATION, AND TABLETOP EXERCISE PROGRAM
(CONTINUED)

Category	Exercise Title and Type	Purpose	Exercise Freq.	Position or Title of Personnel Required to Participate	# Personnel Participation	# Personnel Participation Completed[(a)]	Form of Verification or Reference
				• Gas Operations • PSPS PMO • Safety and Infrastructure Protection Teams (SIPT)			
Operations Based	Wildfire FE	Provide electrical corporation a way to determine its readiness to respond to a wildfire. Identify gaps or problems with existing policies and plans. Help personnel understand roles during a wildfire emergency. Serve as a training tool	Annually (before July 1)	• Electric Distribution • Transmission Grid Operations • Electric Transmission • Electric Field Operations • Information Technology • Electric Incident Investigations • Corporate Safety • Corporate Security • CRESS • Aviation Services • Corporate Affairs • Supply Chain Logistics Customer Care • Human Resources • Marketing & Communications • PSPS Technology/ Operations • Meteorology • Public Affairs • Temporary Generation • HAWC • Finance	248	310	Exercise Plan, player documentation, attendance rosters, AAR

TABLE 8-41:
INTERNAL DRILL, SIMULATION, AND TABLETOP EXERCISE PROGRAM
(CONTINUED)

Category	Exercise Title and Type	Purpose	Exercise Freq.	Position or Title of Personnel Required to Participate	# Personnel Participation	# Personnel Participation Completed[(a)]	Form of Verification or Reference
				• Vegetation Management • Power Generation • Gas Operations • PSPS PMO • SIPTs			
Operations Based	PSPS FSE	Simulate R5-Plus weather and extreme wildfire risk conditions to test PG&E's ability to prepare for, respond to, and recover from a PSPS event in alignment with the CERP, PSPS Annex, and other LOB-specific plans. Challenge players to respond in real-time to solve operational concerns. Identify gaps or problems with existing policies and plans Help personnel understand roles during a wildfire emergency. Serve as a training tool.	Annually (before July 1)	• Electric Distribution • Transmission Grid Operations • Electric Transmission • Electric Field Operations • Information Technology • Electric Incident Investigations • Corporate Safety • Corporate Security • CRESS • Aviation Services • Corporate Affairs • Supply Chain Logistics Customer Care • Human Resources • Marketing & Communications • PSPS Technology/Operations • Meteorology • Public Affairs • Temporary Generation	248	310	Exercise Plan, player documentation, attendance rosters, AAR

TABLE 8-41:
INTERNAL DRILL, SIMULATION, AND TABLETOP EXERCISE PROGRAM
(CONTINUED)

Category	Exercise Title and Type	Purpose	Exercise Freq.	Position or Title of Personnel Required to Participate	# Personnel Participation	# Personnel Participation Completed[(a)]	Form of Verification or Reference
				• HAWC • Finance • Vegetation Management • Power Generation • Gas Operations • PSPS PMO • SIPTs			

(a) # of Personnel Participation Completed is based on 2022 figures.
(b) PG&E does not require attendance at seminars.

8.4.2.3.2 External Exercises

The electrical corporation must report on its program(s) for conducting external discussion-based and operations-based exercises for both wildfire and PSPS emergency events. This must include, at a minimum:

- *The types of discussion-based exercises (e.g., seminars, workshops, TTXs, games) and operations-based exercises (e.g., drills, FEs, FSEs);*
- *The schedule and frequency of exercise programs;*
- *The percentage of public safety partners who have participated in these exercises; and*
- *How the electrical corporation tracks who has completed the exercises.*

Table 8-42 provides an example of the minimum acceptable level of information.

External discussion-based and operations-based exercises may include participation from PG&E Functional Areas (Customer, PSPS, PMO, etc.) and from external, public agencies. Generally, PG&E invites representatives from federal, state, and local agencies to participate in or observe the annual CERP exercise. The agencies that are invited may include:

- Local emergency management agencies and offices of emergency services;
- CPUC;
- California Independent System Operator;
- California Energy Commission;
- Cal OES;
- Non-Governmental Organizations;
- Voluntary Organizations; and
- CBOs.

External partners from various regions of our service territory are invited to participate in the functional or FSE planning meetings for both PSPS and wildfire exercises. These planning meetings include the external partners listed above. The scope of the exercise scenario includes transmission and distribution level customers in the counties wanting to participate, so they can practice their response to a PSPS or wildfire event. Many external partners also choose to observe the exercise and understand how PG&E practices their response to such emergencies, while other external partners may prefer to participate in our discussion-level TTXs.

Participation Tracking

Participation in the field level exercises was documented through PG&E Learning, course code PSPS-0320. The percentages of staff who have completed/participated in the exercises are not available because there was not a targeted number to measure against. A total participant count is available.

For more details on external drills, simulations, and TTXs, please see Table 8-42, below:

TABLE 8-42:
EXTERNAL DRILL, SIMULATION, AND TABLETOP EXERCISE PROGRAM

Category	Exercise Title and Type	Purpose	Exercise Frequency	Position or Title of Personnel Required to Participate	# Personnel Participation Required[(a)]	# Personnel Participation Completed	Form of Verification or Reference
Discussion Based	Wildfire Response Seminar	Provide an overview of PG&E's plans, procedures, and tools used to respond to and mitigate the effects of a Wildfire.	Annually	• EOC team members • Emergency Field Operations • Electric Distribution Emergency Center (EDEC) • Electric Transmission Emergency Center (ETEC) • Gas Emergency Center (GEC) staff • PSS • PSPS PMO	0[(b)]	46	Attendance record and Outlook invitation
Discussion Based	PSPS Response Seminar	Understand the PSPS Program and the history of the PSPS regulation requirements and how we are making these required improvements Explain the PSPS Process at a high level Understand the importance of Meteorology's role before and during a PSPS event Learn how "Scoping" comes into play and how it sets the tone for the event Understand the roles and responsibilities of PG&E's other LOBs and more specifically, how each program communicates, prepares, responds, and recovers from an incident.	Annually	• EOC team members • Emergency Field Operations • EDEC • ETEC • GEC staff • PSS • PSPS PMO	0	126	Attendance records and Outlook invitation

TABLE 8-42:
EXTERNAL DRILL, SIMULATION, AND TABLETOP EXERCISE PROGRAM
(CONTINUED)

Category	Exercise Title and Type	Purpose	Exercise Frequency	Position or Title of Personnel Required to Participate	# Personnel Participation Required[(a)]	# Personnel Participation Completed	Form of Verification or Reference
Discussion Based	PSPS Event TTX	The TTX is aimed at discussing the various stages of the PSPS Procedural Flow (ProFlow) process with internal LOBs and External Agencies PSPS TTX simulates R5-Plus weather conditions to test PG&E's ability to prepare for, respond to, and recover from a PSPS event. TTX aims to help PG&E response teams apply the PSPS specific knowledge provided by the training series in a realistic scenario. • CERP • PSPS Annex • Other LOB-specific plans	Annually	• Electric Distribution • Transmission Grid Operations • Electric Transmission • Electric Field Operations • Information Technology • Electric Incident Investigations • Corporate Safety • Corporate Security • CRESS • Aviation Services • Corporate Affairs • Supply Chain Customer Care • Human Resources • Marketing & Communications • PSPS Technology/Operations • Meteorology • Public Affairs • Temporary Generation	0	130	Exercise situation manual, attendance records, and After-Action Report

TABLE 8-42:
EXTERNAL DRILL, SIMULATION, AND TABLETOP EXERCISE PROGRAM
(CONTINUED)

Category	Exercise Title and Type	Purpose	Exercise Frequency	Position or Title of Personnel Required to Participate	# Personnel Participation Required[(a)]	# Personnel Participation Completed	Form of Verification or Reference
				• HAWC • Finance • Supply Chain • Vegetation Management • Power Generation • Gas Operations • PSPS PMO • SIPTs			
Operations Based	Wildfire FE	• Provide electrical corporation a way to determine its readiness to respond to a wildfire. • Identify gaps or problems with existing policies and plans • Help personnel understand roles during a wildfire emergency. • Serve as a training tool.	Annually	• Electric Distribution • Transmission Grid Operations • Electric Transmission • Electric Field Operations • Information Technology • Electric Incident Investigations • Corporate Safety • Corporate Security • CRESS • Aviation Services • Corporate Affairs • Supply Chain Logistics • Customer Care	0	298	Exercise Plan, player documentation, attendance rosters, AAR

TABLE 8-42:
EXTERNAL DRILL, SIMULATION, AND TABLETOP EXERCISE PROGRAM
(CONTINUED)

Category	Exercise Title and Type	Purpose	Exercise Frequency	Position or Title of Personnel Required to Participate	# Personnel Participation Required[(a)]	# Personnel Participation Completed	Form of Verification or Reference
				• Human Resources • Marketing & Communications • PSPS Technology/Operations • Meteorology • Public Affairs • Temporary Generation • HAWC • Finance • Vegetation Management • Power Generation • Gas Operations • PSPS PMO • SIPTs			
Operations Based	PSPS FSE	• Simulate R5-Plus weather and extreme wildfire risk conditions to test PG&E’s ability to prepare for, respond to, and recover from a PSPS event in alignment with the CERP, PSPS Annex, and other LOB-specific plans.	Annually	• Electric Distribution • Transmission Grid Operations • Electric Transmission • Electric Field Operations • Information Technology • Electric Incident Investigations • Corporate Safety	0	298	Exercise Plan, player documentation, attendance rosters, AAR

TABLE 8-42:
EXTERNAL DRILL, SIMULATION, AND TABLETOP EXERCISE PROGRAM
(CONTINUED)

Category	Exercise Title and Type	Purpose	Exercise Frequency	Position or Title of Personnel Required to Participate	# Personnel Participation Required[(a)]	# Personnel Participation Completed	Form of Verification or Reference
		• Challenge players to respond in real-time to solve operational concerns. • Identify gaps or problems with existing policies and plans • Help personnel understand roles during a PSPS emergency • Serve as a training tool		• Corporate Security • CRESS • Aviation Services • Corporate Affairs • Supply Chain Logistics Customer Care • Human Resources • Marketing & Communications • PSPS Technology/Operations • Meteorology • Public Affairs • Temporary Generation • HAWC • Finance • Vegetation Management • Power Generation • Gas Operations • PSPS PMO • SIPTs			

Note: PG&E does not require attendance at seminars.

(a) # of Personnel Participation Completed is based on 2022 figure.

(b) PG&E does not require external participation in our exercises. External participants are invited and encouraged to participate, but not required.

8.4.2.4 Schedule for Updating and Revising Plan

The electrical corporation must provide a log of the updates to its emergency preparedness plan since 2019 and the date of its next planned update.

Updates should occur every two years, per R.15-06-009 and D.21-05-019. For each update, the electrical corporation must provide the following:

- *Year of updated plan;*
- *Revision type (e.g., addition, modification, elimination);*
- *Component modified (e.g., communications, training, drills/exercises, protocols/procedures, MOAs);*
- *A brief description of the lesson learned that informed the revision; and*
- *A brief description of the specific addition, modification, or elimination.*

Table 8-43 provides an example of the minimum acceptable level of information.

PG&E maintains an annual update schedule for the CERP and its associated annexes including PG&E's Wildfire and PSPS annexes in its Company Emergency Response Plans Standard (EMER-2001S). Last updated on April 26, 2022, EMER-2001S provides a CERP hazard and functional annex update schedule. For more details, please see Table PG&E-8.4.2-4 in Appendix F.

Updates to the CERP can be found in the Change Record logs. For more details on the logs from 2019 through August 4, 2021 (the date of the currently published CERP document, version 7.0) please see Table PG&E-8.4.2-5 in Appendix F.

Details on wildfire-specific updates to the Emergency Preparedness Plan see Table 8-43 in Appendix F.

8.4.3 External Collaboration and Coordination

8.4.3.1 Emergency Planning

In this section, the electrical corporation must provide a high-level description of its wildfire and Public Safety Power Shutoff (PSPS) emergency preparedness coordination with relevant public safety partners at state, county, city, and tribal levels within its service territory. The electrical corporation must indicate if its coordination efforts follow California's Standardized Emergency Management System (SEMS) or, where relevant for multi- jurisdictional electrical corporations (e.g., PacifiCorp), the Federal Emergency Management Agency National Incident Management Systems, as permitted by General Order (GO) 166. The description must be no more than a page.

In addition, the electrical corporation must provide the following information in tabular form, with no more than one page of information in the main body of the Wildfire Mitigation Plan (WMP) and a full table, if needed, in an appendix:

- *List of relevant state, city, county, and tribal agencies within the electrical corporation's service territory and key points of contact, with associated contact information. Where necessary, contact information can be redacted for the public version of the WMP.*
- *For each agency, whether the agency has provided consultation or verbal or written comments in preparation of the most current wildfire- and PSPS-specific emergency preparedness plan. If so, the electrical corporation should provide the date, time, and location of the meeting at which the agency's feedback was received.*
- *For each agency, whether it has a Memorandum of Agreement (MOA) with the electrical corporation on wildfire or PSPS emergency preparedness, response, and recovery activities. The electrical corporation must provide a brief summary of the MOA, including the agreed roles and responsibilities of the external agency before, during, and after a wildfire or PSPS emergency.*
- *In a separate table, a list of current gaps and limitations in the electrical corporation's existing collaboration efforts with relevant state, county, city, and tribal agencies within its territory. 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, a form of verification that can be provided upon request for compliance assurance.*

The electrical corporation must reference the Utility Initiative Tracking ID where appropriate.

Utility Initiative Tracking IDs: EP-02; EP-03; EP-04; EP-05; EP-06

As part of PG&E's wildfire and PSPS emergency preparedness efforts, we regularly engage with public safety partners at the state, county, city, and tribal 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.

- 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; California Governor's Office of Emergency Services (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 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; highlight programs of interest; review accomplishments; receive feedback; and discuss upcoming city and county work that may 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.

- Tabletop and Functional Exercises (FE): Drills that to test our communication strategies during wildfire and PSPS outages and identify areas for improvement.

- Community Wildfire Safety Program Trainings and Workshops (Ad-hoc): Trainings and workshops for agencies and other public safety partners.

- Review of PG&E's Emergency Preparedness Plans: We give local governments an opportunity to conduct a bi-annual review of our Electric Annex, pursuant to Public Utilities Code (Pub. Util. Code) 768.6(b)(1)(c), and in compliance with Standard 10 of GO 166. The last bi-annual review was conducted in 2021. Beginning in March 2023 we will meet with cities and counties to give them an opportunity to review PG&E's Company Emergency Response Plan (CERP), ensuring we are complying with engagement standards set forth by the California SEMS.

Table 8-44 shows how we collaborate with state and local agencies. The information provided in Table 8-44 is an excerpt and the completed table, including contact information for the entities listed in this table, is provided in Confidential Appendix I.

We have not encountered any gaps and limitations when collaborating with state and local agencies as shown in Table 8-45 below.

TABLE 8-44:
PG&E'S STATE AND LOCAL AGENCY COLLABORATIONS

Name of State or Local Agency	Point of Contact and Information	Emergency Preparedness Plan Collaboration – Last Version of Plan Agency Collaborated	Emergency Preparedness Plan Collaboration – Collaborative Role	Memorandum of Agreement?	Brief Description of MOA
Alameda County	Derrick Thomas, ACFD Div Chief/ Emergency Management	Regional Working Group: Bay Area (12/9/22)	Review and provide feedback	No	N/A

TABLE 8-45:
KEY GAPS AND LIMITATIONS IN COLLABORATION ACTIVITIES WITH STATE AND LOCAL AGENCIES

Gap or Limitation Subject	Remedial Brief Description	Remedial Action Plan
N/A	N/A	N/A

8.4.3.2 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. 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 (such as fire, law enforcement, OES, municipal governments, Energy Safety, California Public Utilities Commission (CPUC or Commission), and other electrical corporations) at every level of administration (state, county, city, or tribe), as needed.*
- *The names of individual public safety entities.*
- *For each entity, the point of contact for emergency communications coordination, and the contact information, which may be redacted as needed.*
- *Key protocols for ensuring the necessary level of voice and data communications such as interoperability channels, methods for information exchange, format for each data typology, communication capabilities, data management systems, backup systems, common alerting protocols, and messaging, along with associated references in the emergency plan for more details.*
- *Frequency of prearranged communication review and updates.*
- *Date of last discussion-based or operations-based exercises on public safety partner communication.*

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.

Tables 8-46 and 8-47 provide examples of the minimum level of content and detail required.

PG&E is not the lead agency for wildfires. However, PG&E does communicate with Public Safety Partners regarding assets in wildfire impacted areas, outages due to wildfire, and PSPS outages and service restoration. Below is a high-level overview of PG&E's communication efforts with Public Safety Partners during these events.

- Notifying Cal OES and CPUC when PG&E's Emergency Operations Center (EOC) is activated and again at key milestones, including de-energization and restoration.
- 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.
- Live calls from our Grid Control Center to transmission-level entities before de-energization and re-energization.
- Providing localized support for Public Safety Partners, such as water agencies and emergency hospitals, to confirm they have a mitigation plan in place or if backup generation support is needed.
- Conducting ongoing coordination with local County OES and tribal contacts through dedicated Agency Representatives, following the protocols outlined in PG&E's "PSPS Policy & Procedures Guide for Emergency Managers" (Appendix E). These Agency Representatives are directly connected to our EOC and coordinate internally to gather critical, timely, and location-specific information when requested.
- Embedding a PG&E Agency Representative into the Cal OES State Operations Center to answer questions in real-time, at the request of Cal OES.
- 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.
- For PSPS events only, we host the following calls:
  - Live Calls to Public Safety Answer Points or Dispatch Centers when our EOC is first activated for a PSPS to inform them of a potential event as their call volume may increase as customer notifications begin.
  - State Executive Briefings with agencies to provide the latest outage and restoration information and to answer questions.
  - Systemwide Cooperators Calls, where Public Safety Partners in the service territory are invited to join and hear the latest event information.
  - Tribal Cooperator Calls with potentially impacted tribes to provide the latest event information and answer questions in real-time.

PG&E follows communications policies and procedures outlined in the documents listed below. Each document can be located in Appendix E.

- PSPS Policy & Procedures Guide for Emergency Managers;
- CERP;
- PSPS Annex;
- Wildfire Annex; and
- Electric Annex.

Pursuant to Pub. Util. Code 768.6(b)(1)(c) and in compliance with Standard 10 of GO 166, PG&E provides local government stakeholders an opportunity to provide input into our emergency and disaster preparedness plans, ahead of wildfire season. In addition, when in wildfire emergency posture or in-scope for a PSPS event, our Public Safety Specialist Team follows California's SEMS as required by GO 166 and Pub. Util. Code Section 768.6.

Table 8-46 below provides an example of the high-level communication coordination with other public safety partners. The completed table is in Appendix F.

We have not encountered any gaps and limitations when collaborating with public safety partners as shown in Table 8-47 below.

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY PARTNERS

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed	Communication Exercise(s): Date of Planned Next
City	City of Amador	Joyce Davidson, City Clerk	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-47:
KEY GAPS AND LIMITATIONS IN COMMUNICATION COORDINATION WITH PUBLIC SAFETY PARTNERS

Gap or Limitation Subject	Remedial Brief Description	Remedial Action Plan
N/A	N/A	N/A

8.4.3.3 Mutual Aid Agreements

In this section, the electrical corporation must provide a brief overview of the Mutual Aid Agreements (MAA) it has entered into regarding wildfire emergencies and/or disasters, as well as PSPS events. The overview narrative must be no more than one page.

In addition, the electrical corporation must provide the following wildfire emergency information in tabulated format:

- *List of entities with which the electrical corporation has entered into an MAA;*
- *Scope of the MAA; and*
- *Resources available from the MAA partner.*

Table 8-48 provides an example of the minimum level of content and detail required.

Mutual assistance is an essential part of the PG&E's service restoration process and contingency planning. It consists of coordinated agreements among cooperating agencies and/or utility companies to provide personnel, equipment, and material assistance during emergencies.

Mutual assistance can be inbound or outbound and implemented for gas, electric, cybersecurity, or Information Technology skilled workers, and any line of business or functional area needing assistance.

In times of service disruptions caused by storms, fires, or other types of emergencies, PG&E may request mutual assistance from other utilities (inbound). Conversely, PG&E may provide mutual assistance to other utility companies requesting aid (outbound). In all cases, mutual assistance is provided with the expectation that the responding utilities are reimbursed.

The mutual assistance network is supported by Statewide/Intrastate Mutual Assistance agreements. These are agreements, coordinated through the state, incorporate both state and local governmental and non-governmental resources. All available emergency restoration resources (including contractors) will be pooled and allocated to participating utilities in a safe, efficient, transparent, and equitable manner without regard to Regional Mutual Assistance Groups affiliation.

PG&E works with both the California Utilities Emergency Association (CUEA) and the Western Region Mutual Assistance Group (WRMAG) for inbound and outbound resource needs. The CUEA serves as a point-of-contact for critical infrastructure utilities and the Cal OES and other Governmental Agencies before, during and after an event. As the CUEA members are in California, these are the companies that we approach first for a new event. While the WRMAG implements the Edison Electric Institute (EEI) mutual assistance program in the Western United States and Canada.

For more details on PG&E's mutual assistance partners, the scope of each MAA, and the available resources from each partner, please see Table 8-48 below.

TABLE 8-48:
PG&E'S MUTUAL AID AGREEMENTS FOR RESOURCES DURING A WILDFIRE OR DE-ENERGIZATION INCIDENT

Mutual Aid Partner	Scope of Mutual Assistance Agreement	Available Resources from Mutual Aid Partner
CUEA	In the event of an emergency affecting electrical generation, electrical or natural gas transmission, distribution, or related facilities owned or controlled by a party, such party ("requesting party") may request another party ("assisting party") to provide assistance.	Personnel, material, equipment, supplies, or tools, or any other matter made by one party to another requesting party.
Western Region Mutual Assistance Group/ Western Energy Institute (WRMAA/WEI)	The WRMAA agreement, facilitated by WEI, is designed as a tool for all gas and electric utilities throughout the Western United States and Canada. WRMAA is a recognized group implementing the EEI mutual assistance program in the Western United States and Canada.	Personnel, material, equipment, supplies or tools, or any other matter made by one party to another requesting party.
EEI	EEI's mutual assistance program is a voluntary partnership of investor-owned electric companies across the country committed to helping restore power whenever and wherever assistance is needed.	Personnel, material, equipment, supplies or tools, or any other matter made by one party to another requesting party.
American Gas Association (AGA)	This agreement will enhance the collaboration across the natural gas industry with the understanding that our combined resources can quickly restore comfort to communities that are hit by disasters, ensuring Americans have the energy they need and expect for comfortable homes, warm food, and hot showers. Members are committed to the safe and reliable delivery of natural gas and are proud to assist other utilities and communities in their time of need.	Personnel, material, equipment, supplies or tools, or any other matter made by one party to another requesting party.

8.4.4 Public Emergency Communication Strategy

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. 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; and*
- *Current gaps and limitations.*

Reference the Utility Initiative Tracking ID where appropriate.

PG&E is not the lead agency for wildfires, and we do not communicate to Public Safety Partners regarding the status of wildfires.

Our primary objective is to provide our public safety partners and customers who may be impacted by a PSPS event with accurate notifications as soon as possible. This is in accordance with the minimum timelines set forth by the CPUC PSPS Phase 1 Guidelines.[156] These notifications are designed to help ensure that customers have enough time to prepare for, respond to, and stay safe during PSPS outages.

Our annual PSPS notification planning strategy is founded on feedback collected via public safety partner surveys, customer surveys, stakeholder engagement, and regularly scheduled meetings (described in Section 8.4.3.1) or PSPS After Action Review.

The strategy for outages due to a wildfire follows our emergency outage communications strategy in accordance with GO 166.

Please refer to Section 8.4.3.2 for information about how PG&E communicates with Public Safety Partners to inform them of outages due to wildfires and PSPS and service restoration. An overview of PSPS notification, including PSPS restoration notifications are also included in Figure PG&E-8.4.4-1 below.

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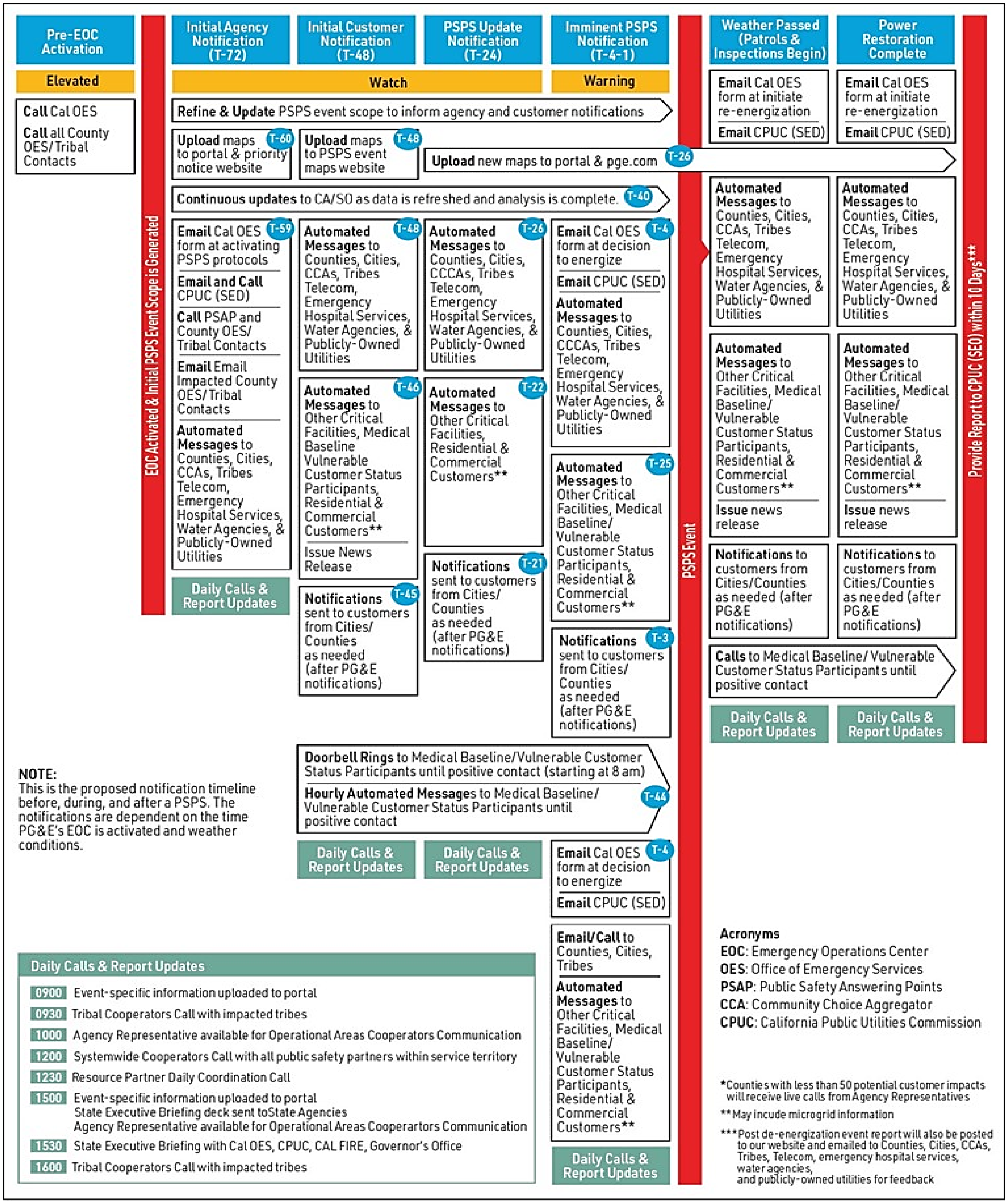
[156] D.19-05-042. See Appendix E.

FIGURE PG&E-8.4.4-1:
PSPS NOTIFICATION TIMELINE



8.4.4.1 Protocols for Emergency Communications

The electrical corporation must identify the relevant stakeholder groups 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. Stakeholder groups include, but are not limited to, the general public, priority essential services, Access and Functional Needs (AFN) populations, populations with limited English proficiency (LEP), tribes, 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.

The electrical corporation must also provide, in tabular form, details of the following:

- *Communication methods; and*
- *Message receipt verification mechanisms.*

Table 8-49 provides an example of the minimum level of content and detail required.

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) customers with LEP and other needs; (6) Community-Based Organization (CBO) in-event support and resources; (7) critical facilities and infrastructure; (8) telecommunications and water providers; (9) transmission-level entities; (10) third-party commodity suppliers; (11) paratransit agencies; (12) media; and (13) the general public.

When PG&E's EOC activates for a potential PSPS event notifications are sent to the CPUC and Cal OES and sent again 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.

PG&E's Liaison and Customer Teams manage most notifications to key stakeholders during a PSPS outage. We send automated calls, texts, and email notifications to public safety partners, customers, and to those that sign up for Address Alerts. We record and send ad-hoc automated calls in English and Spanish to impacted customers and public safety partners. We work with CBOs (In-Language Support) who also provide PSPS notifications to the public through in-person, social media, and local radio.

Our dedicated CBO team maintains communications with CBOs and resource partners before, during, and after PSPS, wildfires, and other emergencies.

During PSPS events, PG&E invites all CBOs to participate in the daily Systemwide Cooperators Call hosted by EOC staff to share PSPS updates. CBOs are also provided courtesy e-mail notifications throughout the event with updates and access to a dedicated e-mail box. CBO resource partners are also sent PSPS priority/advance notifications to prepare resources for deployment, and 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.

PG&E summarizes our protocols for emergency communications to stakeholder groups in Table 8-49 below.

TABLE 8-49:
PG&E'S PROTOCOLS FOR EMERGENCY COMMUNICATION TO STAKEHOLDER GROUPS

Stakeholder Group	Event Type	Method(s) for Communicating	Means to Verify Message Receipt
Local and State Agencies and First Responders	PSPS	Live calls Automated phone calls, texts, and e-mails.	Agency Representative Vendor delivery report
General Residential and SMB Customers	PSPS	Automated phone calls, texts, and e-mails.	Vendor delivery report
MBL Customers, Self-Identified Vulnerable Customers and Electricity Dependent Customers	PSPS	Automated phone calls, texts, and e-mails. If needed, live calls and/or in-person visit from PG&E representative.	Vendor delivery report; Confirmation from PG&E Representative for live calls. Completed Field Order for doorbell rings.
CBOs	PSPS	E-mail	Vendor delivery report
Critical Facilities and Infrastructure	PSPS	Automated phone calls, texts, and e-mails. Live calls as needed.	Vendor delivery report
Telecommunications and Water Providers	PSPS	Automated phone calls, texts, and e-mails. Live calls as needed.	Vendor delivery report
Transmission-level Entities	PSPS	Automated phone calls, texts, and e-mails. Live calls from Grid Control Center/Critical Infrastructure Lead.	Vendor delivery report
Paratransit Agencies	PSPS	Courtesy e-mail.	Zero "bounce back" emails received.
All customers of record	EPSS Outage Notification	Automated phone, text, and e-mails based on communications preference.	Vendor delivery report
All customers of record	Outage due to a wildfire	Automated phone, text, and e-mails based on communications preference.	Vendor delivery report

8.4.4.2 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.

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 (such as font size and color contrast analyzer);*
- *Alert and notification schedules;*
- *Translation of notifications;*
- *Messaging tone and language; and*
- *Key components and order of messaging content (such as hazard, location, and time).*

The narrative must be no more than one page.

PG&E increases public awareness about emergency planning and preparedness using language that is accurate, clear, specific, consistent, and confident in tone. We provide the most current information about our emergency response efforts, rebuilding and recovery, available customer resources, and protection protocols. Content includes news releases, media interviews, and social media posts. We maximize accessibility to this critical information by translating PG&E's website and other critical wildfire safety and PSPS preparedness materials into 16 non-English-languages. Our Contact Center provides translation support in over 240 languages. For customers who have not indicated a designated language preference, we provide notifications in English, with information on how to receive event information in translated languages. We also conduct extensive testing, including dial-test focus groups, to understand the ways to best communicate across demographics.

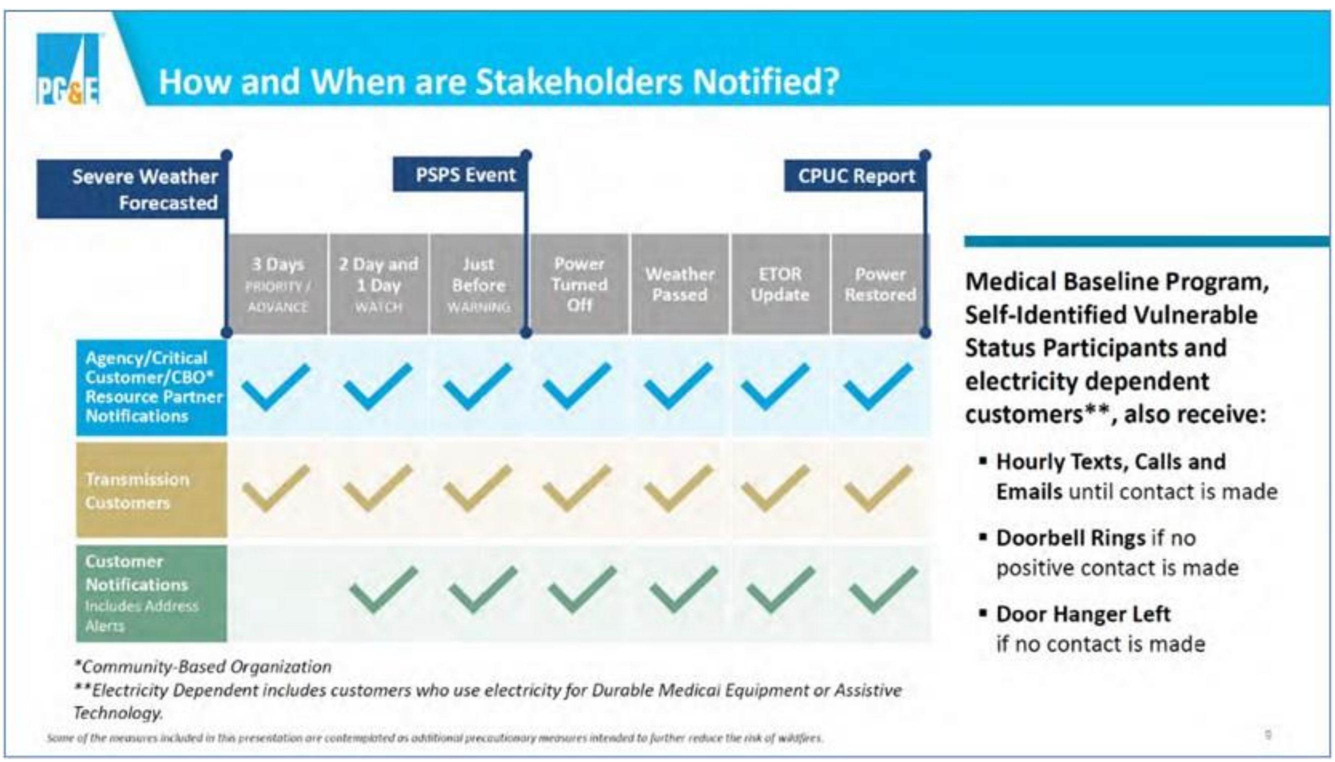
For the deaf/hearing impaired community, PG&E produced a video in American Sign Language (ASL) that explains the PSPS process and is available on our social media channels. Mailed correspondence includes a subject box informing customers what the letter is about and includes key information in bold and large print. Alternate formats in Braille, large print, or audio are available upon request. Our online customer communications, including our website and PSPS customer notification emails, meet Web Content Accessibility Guidelines (WCAG) 2.0 AA accessibility standards. In 2022, new content was tested to WCAG 2.1 AA accessibility standards. Online videos meet WCAG 2.0 AA accessibility standards, with audio description, closed captioning, and written transcripts. Online videos published 2022 and beyond meet WCAG 2.1 AA accessibility standards.

To the extent possible, PG&E schedules notifications for potentially impacted customers two days, one day, and just prior to power shutoff. Customers are also notified upon power restoration. Priority notifications are also made to Public Safety Partners 72-48 hours in advance of de-energization. Our automated notifications comply with the CPUC PSPS Guidelines.[157] Notifications include potentially impacted locations, forecasted date and time of power shutoff, estimated restoration date and time, and links to maps and event-specific information.

Our MBL, self-certifying SIV, and self-identifying dependent medical technology customers receive additional notifications (including calls, texts, and emails) before a PSPS and must confirm receipt, or PG&E sends hourly notifications via phone and text message and conducts a doorbell ring. A door hanger is left if no contact is made during doorbell rings. For more details, see Figure PG&E-8.4.4-2 below.

Additional information including sample messaging and notification sequence are provided in the PG&E October 2022Public Safety Power Shutoff Event Notifications material, see Appendix E.

FIGURE PG&E-8.4.4-2:
HOW AND WHEN STAKEHOLDERS ARE NOTIFIED



157 D.19-05-042. See Appendix E.

8.4.4.3 Current Gaps and Limitations

In tabulated format, the electrical corporation must provide a list of current gaps and limitations in its public communication strategy. 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 8-50 provides an example of the minimum level of content and detail required.

Table 8-50 is a list of current gaps and limitations in our public communications strategy along with the remedial action plan and proposed timeline for resolving them.

TABLE 8-50:
KEY GAPS AND LIMITATIONS IN PG&E'S
PUBLIC EMERGENCY COMMUNICATION STRATEGY

Gap or Limitation Subject	Remedial Brief Description	Remedial Action Plan
De-energization, weather-clear and restoration timing updates	PG&E's objective is to share accurate information with our partners in a timely manner, however some partners have reported receiving missing or incorrect information regarding de-energization, weather all-clear and restoration timing.	In 2023, PG&E plans to examine areas for improvement to ensure the most accurate information is shared with our partners. It is important to note that conditions can change quickly, impacting our ability to provide exact times.
Cancellation Notifications	PG&E makes every attempt to provide notification of the cancellation of a PSPS event, or removal from scope, by notifying all affected entities, including public safety partners. However, these cancellations were not consistently delivered within the target of two hours of the decision to cancel for all portions of the event scope.	In 2023, PG&E plans to examine areas of improvement both from a technology and a process perspective with the intention of delivering cancellation notifications within two hours of a decision to cancel. We expect to identify interim, incremental solutions for use in 2023 by 9/1/2023.
Braille and Large Print Door Hangers	PG&E is developing the process to ensure that customers who request Braille or large print materials receive PSPS doorbell ring materials in their preferred format.	PSPS doorbell ring materials have been developed. However, the processes need to be modified to identify customers requesting information in their preferred format. PG&E is working towards a long-term solution by 6/30/2023.

8.4.5 Preparedness and Planning for Service Restoration

8.4.5.1 Overview of Service Restoration Plan

In this section of the WMP, the electrical corporation must provide an overview of its plan to restore service after an outage due to a wildfire or PSPS event. At a minimum, the overview must include a brief description of the following:

- Purpose and scope of the restoration plan;
- *Overview of protocols, policies, and procedures for service restoration (e.g., means and methods for assessing conditions, decision-making framework, prioritizations, degree of customization). This must include:*
  - *An operational flow diagram illustrating key components of the service restoration procedures from the moment of the incident to response, recovery, and restoration of service.*
- *Resource planning and allocation (e.g., staffing, equipment);*
- *Drills, simulations, and tabletop exercises (TTX);*
- *Coordination and collaboration with public safety partners (e.g., interoperable communications); and*
- *Notification of and communication to customers during and after a wildfire- or PSPS-related outage.*

The electrical corporation may refer to its Pub. Util. Code Section 768.6 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. The overview must be no more than one page.

Reference the Utility Initiative Tracking ID where appropriate.

Purpose and Scope of the Restoration Plan

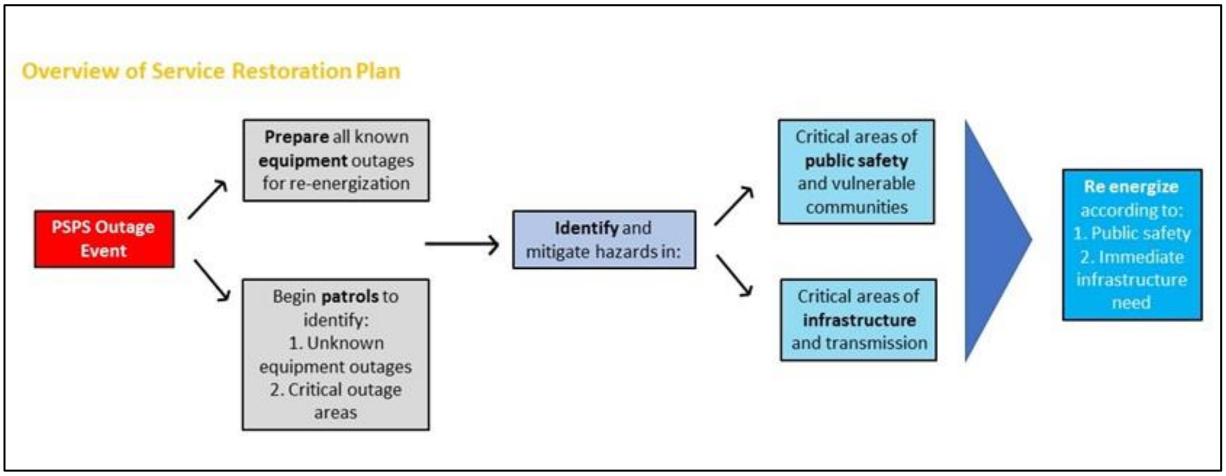
PG&E's purpose is to provide safe and effective re-energization of any area that is de-energized due to PSPS protocol.

The scope of our re-energization plan is to first prepare all known equipment outages for re-energization. Simultaneously we conduct patrols of affected areas based on outage information (e.g., critical versus non-critical). Next, we identify and mitigate hazards first in critical areas with infrastructure and transmission lines with risk to customers and public safety. Impact to vulnerable communities is considered. Some communities may have less infrastructure and transmission damage but still represent critical need.[158]

Overview of Protocols, Policies, and Procedures for Service Restoration

Figure PG&E-8.4.5-1 illustrates key components of the service restoration procedures from the start of the incident to response, recovery, and restoration of service.

FIGURE PG&E-8.4.5-1:
PROTOCOL AND DECISION FLOW FOR SERVICE RESTORATION PLAN



Resource Planning and Allocation

PG&E uses a relevant and rapid training approach to build and maintain an internal workforce that is in a state of readiness, with skills and abilities to react and respond to any incident within the service territory.[159]

Drills, Simulations, and Tabletop Exercises

PG&E develops exercises based on regulatory requirements and schedules them by holding a MYTEP workshop with all Functional Areas. The dates, type, and scope of exercises are tracked via the MYTEP. Attendance at seminars and exercises is tracked. Objectives are defined for each emergency exercise and drill and are tracked accordingly.

Coordination and Collaboration with Public Safety Partners (e.g., Interoperable Communications)

Our primary objective is to provide our public safety partners and customers who may be impacted by a PSPS event with accurate notifications as soon as possible. This is in

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[158] See Appendix E for more information on post-PSPS protocols.

[159] See Appendix E for more information on Adequate and Trained Workforce for Service Restoration.

accordance with the minimum timelines set forth by the CPUC PSPS Phase 1 Guidelines.[160] These notifications are designed to help ensure that customers have enough time to prepare, respond to and stay safe during PSPS outages.

Notifications and Communications to Customers During and After a Wildfire- or PSPS-Related Outage

PG&E makes this critical information accessible by translating in-event notifications, PG&E's website, and other critical wildfire safety and PSPS preparedness materials into 16 non-English-languages. Our Contact Center provides translation support in over 240 languages. For customers who have not indicated a designated language preference, we provide notifications in English, with information on how to receive event information in translated languages. We also conduct extensive testing, including dial-test focus groups, to understand the ways to best communicate across demographics.

160 D.19-05-042. See Appendix E.

8.4.5.2 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

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.

Uses Weather Reports to Pre-Position Manpower and Equipment Before Anticipated Severe Weather That Could Result in an Outage

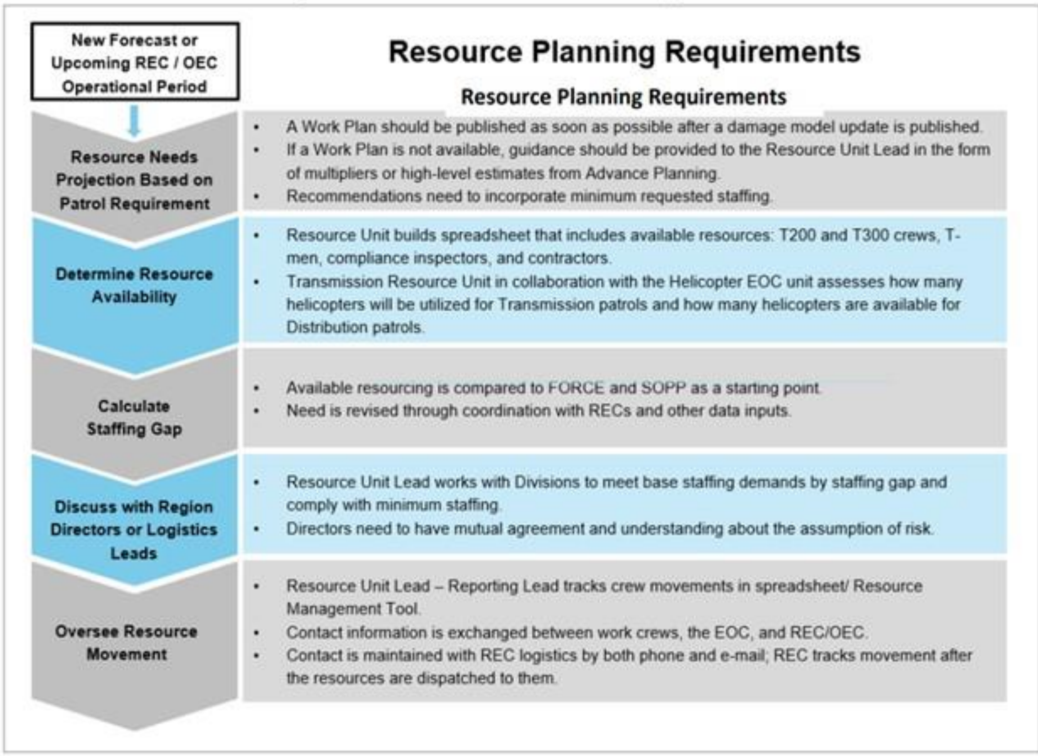
PG&E uses our Distribution System Operation Storm Outage Prediction Project (SOPP) model that our Meteorology team produces to forecast system outages. The SOPP informs staffing for response to PSPS outages.

Sets Priorities

For PSPS outages, the EOC allocates Qualified Electric Worker (QEW) crew resources based on the Field Operations Resource Calculator Estimated Time of Restoration (FORCE) tool outputs and Regional Emergency Center (REC) crew requests. Each Patrol Unit (air, vehicle, or foot) must have a QEW. The FORCE tool provides a starting point for staffing models, but actual staffing may vary depending on available resources. When the demand exceeds the available resources (including mutual aid resources), the Resource Unit will allocate resources based on the FORCE and/or SOPP outputs.

The RECs are accountable for assessing the local situation in collaboration with their local Operations Emergency Center (OEC) resource planning teams. The REC/OEC process is illustrated in Figure PG&E-8.4.5-2 below:

FIGURE PG&E-8.4.5-2:
RESOURCE PLANNING REQUIREMENTS



PG&E has a large, geographically distributed workforce that can mobilize throughout our service territory in response to PSPS outages. To ensure they are prepared, PG&E has built and maintains an internal workforce that is in a constant state of readiness. This includes internal crews and contract crew resources.

PG&E maintains an active PSPS Aviation Program, which is made up of exclusive use helicopter contracts guaranteeing access to as many as 50 helicopters during peak PSPS season. Access to these helicopters allows us to significantly shorten the patrol time for circuits leading to an "all clear," thereby reducing the duration of a PSPS event.

When an outage occurs involving a critical or essential customer, it is noted in PG&E's Outage Management Tool, and those circuits are considered for priority assessment and restoration.

In addition, PG&E maintains three pre-identified Electric Incident Management Teams (IMT). These teams help eliminate ad hoc resource/staffing challenges when multiple events occur simultaneously. An Incident Management Team is comprised of an EOC Commander (Incident Commander) and the Command and General Staff personnel assigned to an incident. 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.

Facilitates Internal and External Communications

PG&E engages in extensive internal and external communications, before, during and after PSPS events. For more information on PG&E's PSPS outreach communications, please see Section 8.4.2.2.

Restores Service

PG&E uses different assessment and restoration strategies based on the complexity of each incident. If there is a small number of outages during a routine response, PG&E uses an order-based strategy in which crews are assigned to each individual outage, as appropriate.

In larger incidents with a greater number of outages, PG&E may use a distribution circuit, transmission line or area-based strategy. In these cases, work is assigned by group/location to highly-impacted circuits, lines, or areas. These strategies improve coordination and assessment/restoration time.

IMT may be activated to support wildfires or other large incidents (e.g., when an incident reaches, or is anticipated to reach, emergency activation level four or higher based on the PG&E CERP incident levels matrix).

PG&E has entered into a number of MAAs with entities who provide resources to assist with service restoration. Under these agreements, entities provide additional personnel, equipment, and materials to support the restoration efforts. PG&E conducts pre-planning with these entities to ensure resources can be deployed quickly. For more details on MAAs, please see Section 8.4.3.3.

8.4.5.3 Drills, Simulations, and Tabletop Exercises

Discussion-based and operational-based exercises enhance knowledge of plans, allow personnel to improve their own performance, and identify opportunities to improve capabilities to respond to wildfire- and PSPS-related service outages. Exercises also provide a method to evaluate an electrical corporation's emergency preparedness plan and identify planning and/or procedural deficiencies.

PG&E uses a progressive exercise approach to train emergency personnel and incorporates Business Continuity and Recovery Planning to test, practice, and strengthen incident preparedness and response. Our approach is described in our Multi-Year Training and Exercise Plan (MYTEP) (Appendix E).

Through the progressive exercise approach, we test and improve our ability to effectively respond to, and recover from, prioritized risks. We accomplish this by using all-hazards capabilities, developing strategies, communicating, collaborating with internal functional units, and coordinating with local, state, and federal partners. The MYTEP lays out a combination of progressive exercises and training requirements to validate our plans and operational readiness in an all-hazards environment. We maintain this integrated training and exercise program for all functional units. Capabilities are typically introduced through a progressive approach, first by a training opportunity such as a seminar or workshop and then exercised in a TTX, FE, or Full-Scale Exercise (FSE). Training and exercises include both Business Continuity and Recovery Planning to enhance emergency personnel's effectiveness in supporting recovery and continuity of operations.

For more details, please see Section 8.4.2.3, which describes the exercises PG&E conducts that allow participants to practice the duties, tasks, and operations they would be expected to perform in a real emergency.

8.4.5.3.1 Internal Exercises

The electrical corporation must report on its program(s) for conducting internal discussion-based and operations-based exercises for service restoration. This must include, at a minimum:

- *The types of discussion-based exercises (e.g., seminars, workshops, TTXs, games) and operations-based exercises (e.g., drills, FEs, FSEs);*
- *The purpose of the exercises;*
- *The schedule and frequency of exercise programs;*
- *The percentage of staff who have completed/participated in exercises; and*
- *How the electrical corporation tracks who has completed the exercises.*

Table 8-51 provides an example of the minimum acceptable level of information.

The information requested in Table 8-51 is provided in Section 8.4.2.3.1.

TABLE 8-51:
INTERNAL DRILL, SIMULATION, AND TABLETOP EXERCISE PROGRAM FOR SERVICE RESTORATION

Category	Exercise Title and Type	Purpose	Exercise Frequency	Position of Title of Personnel Required to Participate	Personnel Required	Personnel Completed	Form of Verification or Reference

Note: Information for this table is provided in Section 8.4.2.3.1.

8.4.5.3.2 External Exercises

The electrical corporation must report on its program(s) for conducting external discussion- based and operations-based exercises for service restoration due to wildfire. This must include, at a minimum:

- *The types of discussion-based exercises (e.g., seminars, workshops, TTXs, games) and operations-based exercises (e.g., drills, FEs, FSEs);*
- *The schedule and frequency of exercise programs;*
- *The percentage of public safety partners who have participated in these exercises; and*
- *How the electrical corporation tracks who has completed the exercises.*

Table 8-52 provides an example of the minimum acceptable level of information.

The Information requested in Table 8-52 is provided in Section 8.4.2.3.2.

TABLE 8-52:
EXTERNAL DRILL, SIMULATION, AND TABLETOP EXERCISE PROGRAM FOR SERVICE RESTORATION

Category	Exercise Title and Type	Purpose	Exercise Frequency	Position of Title of Personnel Required to Participate	Personnel Required	Personnel Completed	Form of Verification or Reference

Note: Information for this table is provided in Section 8.4.2.3.2.

8.4.6 Customer Support in Wildfire and PSPS Emergencies

In this section of the WMP, the electrical corporation must provide an overview of its programs, systems, and protocols to support residential and non-residential customers in wildfire emergencies and PSPS events. The overview for each emergency service must be no more than one page. At a minimum, the overview must cover the following customer emergency services, per Pub. Util. Code Section 8386(c)(21):

- *Outage reporting;*
- *Support for low-income customers;*
- *Billing adjustments;*
- *Deposit waivers;*
- *Extended payment plans;*
- *Suspension of disconnection and nonpayment fees;*
- *Repair processing and timing;*
- *List and description of community assistance locations and services;*
- *MBL support services; and*
- *Access to electrical corporation representatives.*

Reference the Utility Initiative Tracking ID where appropriate.

PG&E implements programs, systems, and protocols to support residential and non-residential customers in the event of wildfire emergencies and PSPS events. An overview of the emergency services that PG&E provides in these events are described below.

Outage Reporting

During wildfires, PG&E follows the established emergency communication framework outlined in our CERP, GO 166 standards, and the Electric Emergency Plan (Appendix E). PG&E uses notification systems to alert customers and public safety partners of planned or unplanned electric outages, such as those related to wildfires. We send automated notifications via call, text message, and e-mail to notify recipients of major events affecting their area and at key milestones 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 times of restoration, and notification once power is restored (where possible). Customers with language preference 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 status of the outage. See Section 8.4.4 for additional information related to PSPS event notifications.

Support for Low-Income Customers

PG&E provides support for low-income customers, including freezing California Alternate Rates for Energy (CARE) eligibility standards and high usage post enrollment verification requests, increasing the assistance cap for emergency assistance program, and modifying qualification requirements for the Energy Savings Assistance Program by allowing customers to self-certify that they meet income qualifications. PG&E leverages our 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. This 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.

Billing Adjustments

Discontinue Billing and Prorate Minimum Delivery Charges

Customers whose service has been disrupted or degraded because of wildfire have their billing discontinued without being assessed 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 our approach for any bills in the area requiring estimation.

In accordance with our Emergency Consumer Protection Plan (Decision (D.) 19-07-015), PG&E also 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 re-establish 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.[161] D.19-07-015 also requires PG&E to expedite move-in and move-out service requests for affected

[161] 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.

customers.[162] PG&E expedites these requests based on the date requested by the customer,[163] consistent with our Emergency Consumer Protection Plan.

Deposit Waivers

PG&E waives security deposit requirements to re-establish service for customers whose home(s) or small business(es) were destroyed by the disaster. In addition to offering this protection, the Commission adopted D.20-06-003 in June 2020, which prohibits PG&E from requiring re-establishment of service deposits from residential customers.[164] PG&E stopped requiring such deposits from customers, consistent with this decision.

Extended Payment Plans

Following a disaster, PG&E offers impacted and red tagged customers our most lenient payment arrangement term, which requires a 20 percent down payment and a repayment period of 12 months for red tagged customers and 20 percent down payment and a repayment period of 8 months for impacted accounts. All residential customers are eligible for payment arrangements up to 12 months in accordance with D.20-06-003. 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.

The Commission approved PG&E Advice Letter (AL) 4145-G/5643-E on October 30, 2019. This AL revised PG&E's Emergency Consumer Protection Plan under Gas and Electric Rule 1 in compliance with D.19-05-037, OP 24.[165]

Suspension of Disconnection and Nonpayment Fees

PG&E suspends disconnections for all red tagged customers for up to 12 months from the Governor or President's emergency proclamation. PG&E waives deposits as described previously and does not charge late fees.

Repair Processing and Timing

D.19-07-015 requires PG&E to offer repair processing and timely assistance to utility customers pursuant to CPUC Section 8386(c)(18). PG&E works with the impacted community to communicate priorities and timelines for repairs and restoration. Specifically, PG&E calls red tagged customers directly to notify them of the services available and to provide a single point of contact at PG&E for related support, including providing information on the process for receiving temporary power. In addition to

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162 D.19-07-015, pp. 58-59, COL 14. See Appendix E.

163 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.

164 D.20-06-003, p. 147, OP 9. See Appendix E.

165 D.19-05-037, p. 64, OP 24. See Appendix E.

directly contacting red tagged customers, impacted customers have access to utility representatives through multiple channels, such as PG&E's call center, public affairs and customer account representatives, and field teams.

List and Description of Community Assistance Locations and Services

Community Resource Centers

During a PSPS event, PG&E will open Community Resource Centers (CRC) where community members can access basic resources including:

- A safe location to charge electronic devices and medical equipment;
- Up-to-date information about the PSPS event; and
- Bottled water, snacks, blankets, Americans with Disabilities Act-accessible restrooms, and Wi-Fi when possible.

Additionally, indoor CRCs have heating/cooling, bagged ice, and privacy screens for nursing mothers and other medical needs.

PG&E continues to build out our 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. as of November 22, 2022, our portfolio has 114 indoor sites and 287 outdoor sites.

When a PSPS event is imminent, PG&E evaluates the scope of the event and proposes CRC sites to activate based on estimated 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 mapped onto the outage map, so visitors can easily identify which CRC is closest to them by looking up their address. We also communicate CRC site locations through press releases, social media posts, and local government outreach. Lastly, customer text and email notifications include a hyperlink to PG&E's PSPS webpage, where customers can find all relevant CRC information.

PG&E has taken steps to make CRCs accessible to all visitors. This includes ongoing engagement and coordination with community stakeholders, site and material preparation, and in-event considerations. While PG&E is proud of the efforts to date, we continue to solicit feedback from AFN customers and stakeholders and implement improvements for CRC accessibility.

Information cards for visitors are available in Braille and information cards and other digital resources are available in 15 non-English languages and large print, which can be printed on-site. Staff with language skills other than English self-identify on their nametags and are strategically assigned to CRCs based on local demographics and feedback from community partners. If additional in-language support is needed, customer staff have a phone number to call where translation services are available in over 200 languages. Language Line, an online service for video remote interpreting calls is available on laptop computers located at every CRC, allowing for visitors who may be Deaf or hard of hearing to use ASL for communication. For details on PG&E's Community Resource Center program, see our CRC plan submitted as Appendix A of the 2022 Pre-Season Report.

Wildfire Support

When a wildfire occurs, PG&E evaluates the scope of the event and partners with CBOs to activate services based on the wildfire footprint and estimated customer impact. PG&E works with lead agencies such as CalFire and OES to determine the appropriate assistance programs based on community needs and guidance from the lead agency, including support for Access and Functional Needs (AFN) and Medical Baseline (MBL) customers. CRCs are used where applicable. Please refer to PG&E's 2023 AFN Plan for a list of current community assistance partnerships.

Medical Baseline Support Services

Medical Baseline Marketing, Education & Outreach: MBL Program is an assistance program for residential customers with extra energy needs due to qualifying medical equipment and conditions. Our MBL Program applies to both wildfire and PSPS events. PG&E encourages customers to participate in the MBL Program throughout the year with targeted acquisition emails and letters, digital media advertisement, as well as radio ads.[166] 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 email notifications to notify potentially impacted MBL customers. Potentially impacted MBL customers will continue to receive doorbell rings if they do not acknowledge notifications before PSPS. To ensure that PG&E has accurate customer contact information, we will send out Contact Information Update reminder postcards and email to MBL customers in the HFRA who may be impacted by PSPS, prior to wildfire season in 2023. We 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

166 Res.E-5169 (Sept. 23, 2021), "Implementing Improvements to MBL Programs and Affirming Compliance with SB 1338." Pursuant to this resolution, PG&E, Southern California Edison Company, and San Diego Gas & Electric Company will establish a goal to increase MBL enrollment relative to 2018 levels by 7 percent in 2021, 8 percent above 2018 levels in 2022, and 9 percent above 2018 levels in 2023. As of June 2022, PG&E has surpassed its MBL enrollment targets for 2022.

is because the financial benefits were provided to MBL customers solely via augmented baseline allowances that are applicable only to tiered rates.

PG&E filed Application (A.) 20-10-006 where it proposed to offer an additional option for MBL customers who wish to take service on non-tiered TOU rates called “D-MEDICAL.” This option retains the approximate value of the financial benefits MBL customers receive on tiered rates via a 12 percent line-item discount. Subsequently, PG&E and the other parties to the proceeding negotiated an all-party settlement agreement that was approved by the Commission and that endorsed PG&E’s proposed option for its MBL customers to receive a 12 percent line-item discount on non-tiered TOU rates.

D-MEDICAL will be implemented in multiple phases. In the initial phase, PG&E will implement D-MEDICAL to coincide with the launch of its new electrification rate, Electric Home (Schedule E-ELEC), which will also be implemented in phases. PG&E anticipates that D-MEDICAL will be available to all eligible customers on the E-ELEC rate by the end of 2023. Additionally, PG&E will implement D-MEDICAL for the remaining open non-tiered rates, EV2-A and E-TOU-D, via a subsequent AL. That AL will also include a plan to update all relevant MBL forms and existing outreach to reflect the availability of D-MEDICAL on all open non-tiered rates.

Joint IOU Petition to Modify MBL Renewal Process: Previously, D.02-04-026 directed the IOUs to require customers with a permanent disability to self-certify their MBL program eligibility every two years and to require customers without a permanent disability to self-certify each year and provide a doctor’s certification every two years. On August 3, 2022, the IOUs jointly filed a petition to modify D.02-04-026 requesting to change the renewal requirements. The intent of the petition was to update the rules to provide administrative relief to MBL customers while also removing the potential for eligible MBL customers to be inadvertently dropped from the program due to failing to respond to outreach by the IOUs.

The CPUC ruled that the proposed modifications to D.02-04-026 were consistent with the Disability Rights Advocates’ recommendations and would enable customers currently enrolled in the MBL program to remain enrolled more easily than the current requirements. Pursuant to D.22-11-033 which was issued on November 17, 2022, the IOUs are required to submit Tier 2 ALs containing implementation plans, timelines, needed tariff revisions, and estimated incremental costs associated with implementing the modifications adopted by the decision.

Access to Electrical Corporation Representatives

D.19-07-015 requires PG&E to offer repair processing and timing assistance and timely access to utility customers pursuant to CPUC Section 8386(c)(18).

PG&E works with impacted communities to communicate priorities and timelines for repairs and restoration. Specifically, PG&E calls red tagged customers directly to notify them of the protections available and to provide a single point of contact at PG&E for related support. This includes providing information on the process for receiving temporary power. In addition to directly contacting red tagged customers, impacted-customers have access to utility representatives through multiple channels, such as PG&E’s call center, customer account representatives, and field teams.

8.5 Community Outreach and Engagement

8.5.1 Overview

In accordance with California Public Utilities Code (Pub. Util. Code) Section 8386(c)(19)(B) each electrical corporation must provide its plans for community outreach and engagement before, during, and after a wildfire. The electrical corporation must also provide its plans for outreach and engagement related to Public Safety Power Shutoff (PSPS), outages from protective equipment and device settings, and Vegetation Management (VM).

In this section, the electrical corporation must identify objectives for the next 3- and 10-year periods, targets, and performance metrics related to the following community outreach and engagement mitigation initiatives:

- *Public outreach and education awareness for wildfires, PSPS, outages from protective equipment and device settings, and VM;*
- *Public engagement in the Wildfire Mitigation Plan (WMP) decision-making process;*
- *Engagement with Access and Functional Needs (AFN) populations, local governments, and tribal communities;*
- *Collaboration on local wildfire mitigation and planning; and*
- *Best practice sharing with other electrical corporations from within and outside of California.*

Community outreach and public 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 Enhanced Powerline Safety Settings (EPSS). Pacific Gas and Electric Company (PG&E) leverages the Safety Partner, Community-Based Organizations (CBO) and customer engagement opportunities described in Section 8.4.3 to gather feedback on the engagement plans for PSPS and EPSS outages. Targeted and general outreach is then developed and conducted in advance of, during, and after peak wildfire season to ensure all customers and stakeholders understand the programs, their wildfire safety benefits, the potential impacts, and support that is available to them.

8.5.1.1 Objectives

Each electrical corporation must summarize the objectives for its 3-year and 10-year plans for implementing and improving its community outreach and engagement. These summaries must include the following:

- *Identification of which initiative(s) in the WMP the electrical corporation is implementing to achieve the stated objective, including Utility Initiative Tracking IDs;*
- *Reference(s) to applicable codes, standards, and best practices/guidelines and an indication of whether the electrical corporation exceeds an applicable code, standard, or regulation;*
- *Method of verifying achievement of each objective;*
- *A completion date for when the electrical corporation will achieve the objective; and*
- *Reference(s) to the WMP section(s) or appendix, including page numbers, where the details of the objective(s) are documented and substantiated.*

This information must be provided in Table 8-53 for the 3-year plan and Table 8-54 for the 10- year plan. Examples of the minimum acceptable level of information are provided below.

Community Events

PG&E recognizes the importance of engaging with customers and communities on key wildfire safety programs and to do this we are committed to holding informational and interactive events with our customers. We also recognize the need to ensure these events are focused on relevant topics and in areas where they will produce the most customer safety benefits. Events like webinars allow PG&E to disseminate important and current information about fire safety and preparedness, to hear and respond to customer questions, and to provide an open and immediate channel for resolving concerns.

This is why safety-focused events will continue in 2023 and beyond. For 2023, we are planning a variety of different events such as regional town halls and community webinars so we can engage directly with our customers.

As part of our Regional Service Model, PG&E will be holding quarterly Regional Town Halls in each of PG&E's five regions. We will use these events to convey local wildfire safety information in advance of wildfire season. PG&E will make a good-faith effort to have an officer present at each of these events, as appropriate.

In addition, we are planning to hold the equivalent of monthly community events, based on the impacts that wildfire safety efforts have had on the community (i.e., PSPS, EPSS, Undergrounding, VM, etc.). These events could include, but are not limited to: webinars, in-person open houses, safety fairs, and in-person answer centers. This flexibility will allow us to be targeted in our outreach approach so we can respond effectively to the needs of each community. Due to the continuing Coronavirus (COVID-19) pandemic, PG&E will continue to follow prevailing public health guidelines, including holding meetings virtually when possible. In years' past, PG&E has been able to collaborate with agencies, critical facilities, and other stakeholders on outreach forums, including designing in-person meetings and community town halls. The COVID-19 pandemic prevented most in-person engagement efforts for most of 2021 and 2022 and likely will impact in-person engagements in 2023 as well.

In addition to general wildfire safety engagement events, PG&E will continue to hold webinars for specific audiences, including: customers with AFN; K-12 schools; in-language webinars for customers who speak Spanish, Chinese, Hmong, and Tagalog; large commercial customers including hospitals and health care providers; CBOs; and customers and communities impacted frequently by outages on circuits with EPSS.

To maximize the opportunity for community engagement at these meetings, we will continue to employ outreach efforts that have proven effective at drawing customers to them. Outreach will include: direct-to-customer e-mail; promotion on social media channels; informing local and regional news and information media outlets; coordinating with local, regional, and tribal elected officials, other agencies, and CBOs; and providing Spanish and Chinese captions and audio translation, as well as American Sign Language (ASL) interpreters.

- Table 8-53 and Table 8-54 Information Summary: In Table 8-53 and Table 8-54, we are providing the objective name (Objective Name), a description of the objective (Objective Description), the anticipated outlook of the objective (3-Year/10-Year Outlook), the planned due date for the objective (Completion Date), the applicable Initiative Tracking ID (Initiative Tracking ID), "Applicable Regulations, Codes, Standards, and Best Practices", "method of verification", and "section and page #" references. As noted in Section 7.2.1, "Applicable Regulations, Codes, Standards, and Best Practices," "method of verification," and "section and page #" columns are not a part of the objective. Instead, the controlling objective information is in the "Objective Description" and "Completion Date" columns.

- Reporting: Unless changed through Office of Energy Infrastructure Safety's (Energy Safety) Change Order process, PG&E will use the objectives in Table 8-53 and Table 8-54 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 2023-2025 WMP, we discuss current plans for wildfire-related activities beyond the objectives in Table 8-53 and Table 8-54. The timing and scope of these additional activities and work may change. We will not be reporting on these plans or activities in our QDR, QN, or ARC because they are not objectives but are descriptions of plans and activities in our 2023-2025 WMP to provide a complete picture of our wildfire mitigation activities.

- External Factors: All objectives in the below Table 8-53 and Table 8-54 are subject to External Factors which represent reasonable circumstances which may impact execution against objectives including, but not limited to: physical conditions, landholder refusals, environmental delays, 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 ID: We are including Initiative Tracking IDs in each section that has associated targets and objectives. Table 8-53 and Table 8-54 display the Tracking IDs we are implementing to tie the objectives to the narratives and initiatives in the WMP. The Initiative Tracking IDs will also be used for reporting in the QDR.

TABLE 8-53:
COMMUNITY OUTREACH AND ENGAGEMENT INITIATIVE OBJECTIVES (3-YEAR PLAN)

Objective Name	Objective Description	Applicable Initiative(s), Tracking ID(s)	Applicable Regulations, Codes, Standards, and Best Practices	Method of Verification (i.e., Program)	Completion Date	Reference (Section and Page #)
Community Engagement – Meetings	Hold community engagement meetings within the five PG&E regions of service that will include, but are not limited to, a mix of webinars, open houses, town halls, and/or answer centers.	CO-01	Continued from 2022 WMP – Investigation 19-06-015: 2017 North Bay Fires/ 2018 Camp Fire OII	For In-Person Meetings: Third-party prepared meeting summary For Virtual Meetings: Link to recording of session	9/30/2023 9/30/2024 9/30/2025	Section 8.5.2 Page 729

TABLE PG&E-8-54:
COMMUNITY OUTREACH AND ENGAGEMENT INITIATIVE OBJECTIVES (10-YEAR PLAN)

Objective Name	Objective Description	Applicable Initiative(s), Tracking ID(s)	Applicable Regulations, Codes, Standards, and Best Practices	Method of Verification (i.e., Program)	Completion Date	Reference (Section and Page #)
Community Engagement – Meetings in 2026-2032	Continue to hold community engagement meetings within the five PG&E regions of service. This work will include, but not be limited to, a mix of webinars, open houses, town halls, and/or answer centers.	CO-03	Ongoing lessons learned from the WMP and proceedings pertaining to stakeholder engagement and wildfire safety	For In-Person Meetings: Third-party prepared meeting summary For Virtual Meetings: Link to recording of session	12/31/2032	Section 8.5.2 Page 729

8.5.1.2 Targets

Initiative targets are forward-looking quantifiable measurements of activities identified by each electrical corporation in its WMP. Electrical corporations will show progress toward completing targets in subsequent reports, including QDRs and WMP Updates.

The electrical corporation must list all targets it will use to track progress on its community outreach and engagement for the three years of its Base WMP. Energy Safety's Compliance Assurance Division and third parties must be able to track and audit each target. For each initiative target, the electrical corporation must provide the following:

- *Utility Initiative Tracking IDs;*
- *Projected targets for each of the three years of the Base WMP and relevant units;*
- *Quarterly, rolling targets for 2023 and 2024 (PSPS outreach only);*
- *The expected "x% risk impact." for each of the three years of the base WMP. The expected x% risk impact is the expected percentage risk reduction per year, as described in Section 7.2.2.2; and*
- *Method of verifying target completion.*

The electrical corporation's targets must provide enough detail to effectively inform efforts to improve the performance (i.e., reduction in ignition probability or wildfire consequence) of the electrical corporation's community outreach and engagement initiatives.

Table 8-55 and Table 8-56 provide examples of the minimum acceptable level of information.

- Table 8-55 Information Summary: In Table 8-55, we are providing the target name (Target Name), the applicable Initiative Tracking ID (Initiative Tracking ID) and a description of the Target for each applicable year (2023 Target & Unit, 2024 Target & Unit, 2025 Target & Unit), the "% Risk Impact" for each respective year, and the method of verification. As noted in Section 7.2.1, the % Risk Impact and method of verification columns are not a part of the Target. Instead, the controlling target information is in the "Target & Unit" columns for each respective year.

- Table 8-56 Information Summary: Table 8-56 contains the Q2 and Q3 quarterly targets for 2023 and 2024 as well as the year end targets for 2023, 2024, and 2025 for inspections. Please note, the end-of-year (EOY) targets in Table 8-56 are also represented in Table 8-55. For readability and efficiency, the annual targets in Table 8-55 include additional language to provide more context on the quantitative target values, as well as all other required information associated with targets (i.e., method of verification, % risk Impact).Therefore, if additional context is needed to better understand the quarterly target values in Table 8-56, please refer to the

2023 Target & Unit, 2024 Target & Unit, 2025 Target & Unit columns in Table 8-55 that have the same associated target name (Target Name).

- Utility Initiative Tracking ID: We are including Initiative Tracking IDs in each section that has associated targets and objectives. Table 8-55 and Table 8-56 display the Tracking IDs we are implementing to tie the targets to the narratives and initiatives in the WMP. The Initiative Tracking IDs will also be used for reporting in the QDR.

- Reporting: Unless changed through Energy Safety's Change Order process, PG&E will use the Targets in Table 8-55 and Table 8-56 below for quarterly compliance reporting including the QDR, QN, and the ARC. It is also important to note that throughout this 2023-2025 WMP, we discuss current plans for wildfire-related activities in addition to the Targets in Table 8-55 and Table 8-56. The timing and scope of these additional activities and work may change. We will not be reporting on these plans or activities in our QDR, QN, or ARC because they are not Targets but are descriptions of plans and activities in our 2023-2025 WMP to provide a complete picture of our mitigation activities.

- % Risk Impact: The % Risk Impact provided in Table 8-55 is calculated based on the risk reduction of the mitigation initiative divided by total overall utility risk as defined in Section 6.4.2, Section 7.2.2.2, and Section 7.2.2.3. The % Risk Impact provided is an estimate based on the best available workplans applied against the latest risk models as of time of this filing. Please note, 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, for inspection and line sensor related targets, since inspections in of themselves do not reduce risk, instead we provided an "Eyes-on-Risk" value to provide insights into the level of risk being assessed.

- External Factors: All targets in the below Table 8-55 and Table 8-56 are subject to External Factors which represent reasonable circumstances which may impact execution against targets including, but not limited to, physical conditions, landholder refusals, environmental delays, 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.

- High Fire Threat District (HFTD), High Fire Risk Area (HFRA), Buffer Areas: Unless stated otherwise, all initiative work described in Table 8-55 involves work or audits on units or equipment located in, traversing, energizing, or protecting units or equipment in HFTD, HFRA, or Buffer Zone areas.

TABLE 8-55:
COMMUNITY OUTREACH AND ENGAGEMENT INITIATIVE TARGETS BY YEAR

Target Name	Initiative Activity Tracking ID	Reference Section	2023 Target and Unit	x% Risk Impact 2023	2024 Target and Unit	x% Risk Impact 2024	2025 Target and Unit	x% Risk Impact 2025	Method of Verification
Community Engagement – Surveys	CO-02	8.5.2	PG&E will complete two PSPS education and outreach surveys.	N/A	PG&E will complete two PSPS education and outreach surveys.	N/A	PG&E will complete two PSPS education and outreach surveys.	N/A	Survey results and analyses.

TABLE 8-56:
COMMUNITY OUTREACH AND ENGAGEMENT INITIATIVE TARGETS BY QUARTER

Target Name	Initiative Activity Tracking ID	Reference Section	Target End of Q2 2023 and Unit	Target End of Q3 2023 and Unit	End of Year Target 2023 and Unit	x% Risk Impact 2023[(a)]	Target End of Q2 2024 and Unit	Target End of Q3 2024 and Unit	EOY Target 2024 and Unit	x% Risk Impact 2024[(a)]	EOY Target 2025 and Unit	x% Risk Impact 2025[(a)]	Method of Verification
Community Engagement – Surveys	CO-02	8.5.2	1 Survey	1 Survey	2 Surveys	N/A	1 Survey	1 Survey	2 Surveys	N/A	2 Surveys	N/A	Survey results and analyses.

(a) Surveys help PG&E understand the effectiveness of our community outreach and engagement initiatives but do not reduce system risk.

PG&E conducts a pre-wildfire season survey (Pre) and a post-wildfire season survey (Post) of the public to evaluate the effectiveness of our education and outreach efforts prior to, during, and immediately after peak PSPS and wildfire seasons. The Pre-season survey is typically conducted in or around August/September. The field period for the Post-season survey begins soon after peak wildfire season, typically from mid-November to mid-December. The survey has been updated to include questions related to the EPSS Program. With a sample size of over 2,200 completed interviews, the survey is robust enough to conduct analyses at various levels including HFTD tiers, Designated Market Areas, Spanish speakers, and customers with AFN.

The Pre/Post outreach effectiveness surveys are conducted both online and over the phone. The survey is offered in 17 languages for both the online and phone versions.[167]

TABLE PG&E-8.5.1-1:
AVAILABLE LANGUAGES FOR SURVEY

English	Tagalog/Filipino	Arabic	Punjabi
Spanish	Farsi/Persian	Armenian	Russian
Chinese	Japanese	Hindi	Portuguese
Vietnamese	Hmong	Khmer	Thai
Korean			

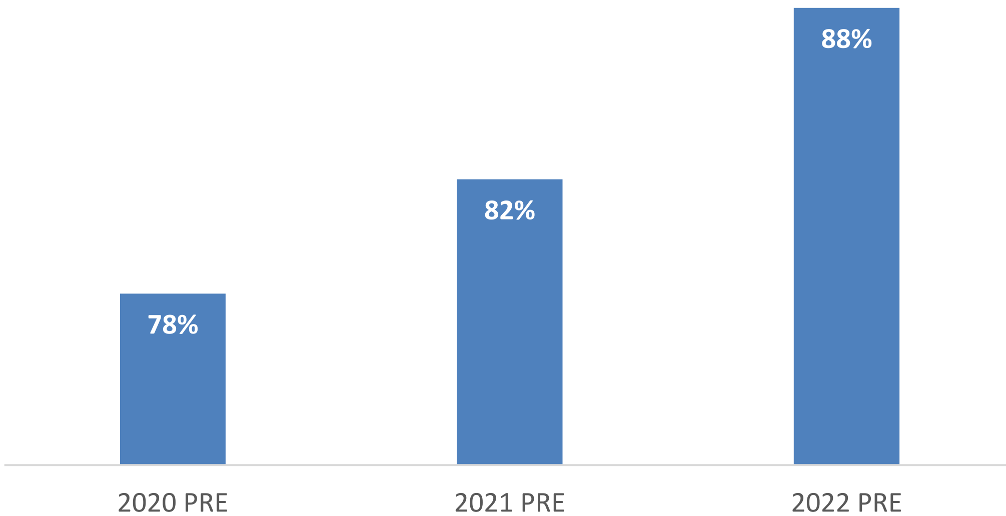
Despite being offered in 16 non-English languages in 2021, only 13 percent of “Pre-Season” survey respondents and 8 percent in the “Post-Season” survey respondents elected to complete the survey in a language other than English. Of those, the overwhelming majority were in Spanish. In 2022, PG&E added an additional language: Armenian.

Recall of the outreach just prior to peak Wildfire/PSPS season in the most impacted areas (HFTD Tiers 2 and 3) has steadily increased, from 78 percent in 2020 to 88 percent in the 2022 Pre-Season survey. Because this is already a high level of recall, we would not expect it to increase much. We will strive to either maintain or increase this level within the survey’s margin of error (±5%). “Recall” is defined as the percentage of survey respondents who answer “Yes” to the following question:

> In the past few months do you recall any communications of any type (i.e., mail, TV, radio, social media, etc.) from PG&E about the threat of wildfires and how you can prepare for them?

[167] Based on PG&E’s assessment, this meets the prevalent language requirement as defined in Decision (D.) 20-03-004, further outlined in PG&E Wildfire and PSPS Outreach Workplan and Budget Advice Letter (AL) 4249 G/5827 E2 (PG&E ID U 39 M), p. 14, filed with the California Public Utilities Commission (CPUC) on May 15, 2020. Following this filing, additional languages were added per the CPUC’s direction. See Appendix E.

FIGURE PG&E-8.5.1-1:
PG&E OUTREACH EFFECTIVENESS SURVEY PRE-SEASON WAVES COMMUNICATIONS RECALL
TIER 2 AND 3 HFTD



8.5.1.3 Performance Metrics Identified by the Electrical Corporation

Performance metrics indicate the extent to which an electrical corporation's WMP is driving performance outcomes. Each electrical corporation must:

- *List the performance metrics the electrical corporation uses to evaluate the effectiveness of its community outreach and engagement in reducing wildfire and PSPS risk.*

For each of those performance metrics listed, the electrical corporation must:

- *Report the electrical corporation's performance since 2020 (if previously collected);*
- *Project performance for 2023-2025; and*
- *List method of verification.*

The electrical corporation must ensure that each metric's name and values are the same in its WMP reporting as its QDR reporting (specifically, QDR Table 2 and QDR Table 3). Metrics listed in this section that are the same as performance metrics required by Energy Safety and reported in QDR Table 2 (Performance Metrics) must match those reported in QDR Table 2. Metrics listed in this section that are not the same as any of the performance metrics identified by Energy Safety and reported in QDR Table 2 must match those reported in QDR Table 3.

The electrical corporation must:

- *Summarize its self-identified performance metric(s) in tabular form; and*
- *Provide a brief narrative that explains trends in the metrics.*

Table 8-57 provides an example of the minimum acceptable level of information.

Table 8-57 provides recorded and projected data regarding the number of customers notified prior to initiation of a PSPS event. Notifying customers prior to initiation of PSPS event ensures customers are aware of the potential outages and the resources available to them. The metric "number of customers notified prior the initiation of PSPS event" is largely weather dependent as this metric will corelate with the frequency, scope, and duration of PSPS events.

**TABLE 8-57:
COMMUNITY OUTREACH AND ENGAGEMENT PERFORMANCE METRICS RESULTS BY YEAR**

Performance Metrics	2020	2021	2022	2023 Projected	2024 Projected	2025 Projected	Method of Verification (e.g., Third-Party Evaluation, QDR)
Number of customers notified prior to initiation of PSPS event	869,000	181,000	0	457,000	451,000	445,000	QDR[(a)]

(a) QDR Table 10, QDR No. 4c.

8.5.2 Public Outreach and Education Awareness Program

The electrical corporation must provide a high-level overview of its public outreach and education awareness program(s) for wildfires; outages due to wildfires, PSPS events, and protective equipment and device settings; service restoration before, during, and after the incidents (as required by Pub. Util. Code Section 8386[c][19][B]); and VM. This includes outreach efforts in English, Spanish, Chinese (including Cantonese, Mandarin, and other Chinese languages), Tagalog, and Vietnamese, as well as Korean and Russian where those languages are prevalent within the service territory.

At a minimum, the overview must include the following:

- *A description of the purpose and scope of the program(s).*
- *References to the Utility Initiative Tracking ID where appropriate.*
- *A brief narrative followed by a tabulated list of all the different target communities it is trying to reach across the electrical corporation's service territory. The target communities list must include AFN and other vulnerable or marginalized populations, but they may also include other target populations, such as communities in different geographic locations (e.g., urban areas, rural areas), age groups, language and ethnic groups, transient populations, or Medical Baseline (MBL) customers. In addition, the electrical corporation must summarize the interests or concerns each community may have before, during, or after a wildfire or PSPS event to help inform outreach and education awareness needs. Table 8-58 provides an example of the minimum acceptable level of information.*
- *A tabulated list of community partners the electrical corporation is working with or intends to work with to support its community outreach and education programs. Table 8-59 provides an example of the minimum acceptable level of information.*
- *A table of the various outreach and education awareness programs (i.e., campaigns, informal education, grant programs, participatory learning) that the electrical corporation implements before, during, and after wildfire, VM, and PSPS events, including efforts to engage with partners in developing and exercising these programs. 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. The electrical corporation must also provide the information on its outreach and education awareness programs in tabulated format. Table 8-60 provides an example of the minimum acceptable level of information.*

Utility Initiative Tracking ID: CO-01; CO-02; CO-03

Prior to peak wildfire season, PG&E designs and executes a comprehensive wildfire safety and PSPS preparedness community outreach strategy, using lessons learned and feedback received from customers and stakeholders. Furthermore, 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.

We recognize that a one-size-fits-all approach to engagement does not necessarily consider a community's specific priorities, and that localized outreach will better inform and engage customers and community groups throughout the territory. Key community groups include: AFN; residential and unassigned Small Medium Business (SMB) customers; property owners and property managers; critical facilities, such as water agencies, communications providers, and hospitals; and CBOs. We incorporate multiple channels and tactics into our engagement approach that enable us to regularly hear and act upon feedback from agencies, CBOs and other community stakeholders, agencies, and communities impacted in prior fire seasons.

While PG&E's engagement for the PSPS Program has advanced in maturity, and will remain an area of focus, other key wildfire mitigation programs are driving additional needs for engagement including EPSS and Undergrounding. In 2023 we will focus on further integrating awareness and education about the EPSS Program into broader Community Wildfire Safety Program (CWSP) customer messaging about wildfire safety outages resulting from programs like PSPS and EPSS. Direct-to-customer mail, e-mail, and other outreach materials outlined in Table 8-60 below are updated to provide overall awareness of the CWSP and programs such as PSPS and EPSS.

PG&E monitors customers and communities who have been impacted by multiple outages on EPSS-enabled circuits. PG&E may leverage automated outage notifications, follow-up Interactive Voice Recording (IVR) 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 critical facilities, 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 Critical Facilities and Infrastructure (CFI) is conducted annually to validate contact information, and coordinate resiliency planning efforts associated with backup generation. In addition, we send an annual letter reminding CFIs that PG&E is not responsible for providing backup power before or during PSPS and wildfire events. We provide critical facilities, including transmission level customers, with advanced notifications and prioritized restoration as outlined in PG&E's 2022 Revised WMP (Section 8.2.5, p. 1049) and additional communications and other resources before and during outages. In alignment with other Investor-Owned Utilities (IOU), CFIs can request a backup power assessment and we provide them online resources, tools, and preparedness information related to their business needs. We do not provide backup generation to individual facilities. However, our policy allows exceptions for CFIs when an outage could have a significant adverse impact to public safety, or if the individual critical customer facility's backup generation and emergency plan fails. To maintain accurate contact information and backup generation needs, we rely heavily on collaboration through engagement with local government and Public Safety Partners by our Account Representatives and PSS related to CFI identification and validation of contact information. Resiliency planning efforts associated with backup generation is conducted annually.

PG&E also follows best practice guidelines and seeks input from the other California IOUs and through our advisory committees to identify additional community groups to include in our public outreach and awareness efforts.

Table 8-58 below lists the communities we engage with around wildfire safety and PSPS preparedness through our comprehensive community outreach strategy.

TABLE 8-58:
PG&E'S 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.
Self-identified Vulnerable (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 8-58:
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 available in 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.

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. We conduct outreach related to emergency preparedness, provide an improved notification experience before and during PSPS events, and offer additional services and resources to these customers in advance of and during PSPS events and wildfires. Outreach to our vulnerable/AFN customers and communities is conducted in accordance with the *Enhanced Customer and Community Support During All Hazards Standard (*EMER-7001S),[168] either directly or in partnership with CBOs.

In 2023, PG&E plans to continue our partnerships with CBOs (67 resource partner CBOs, 38 multicultural media partners, and 299 informational partner CBOs) to increase wildfire safety outreach and education to support our 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 (see Section 8.5.3 for more details about PG&E AFN demographics). PG&E's 2022 PSPS AFN Plan,[169] filed January 31, 2022, provides more details on PG&E's goals, strategies, and tactics to support AFN customers and communities before, during, and after PSPS events. Additional details for 2023 will be included in PG&E's 2023 AFN Plan to be filed January 31, 2023.[170]

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.

Table 8-59 in Appendix F lists the community groups we work with to help provide services and resources to our vulnerable/AFN customers and communities before and during PSPS events and wildfires.

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 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

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168 See Appendix E.

169 Please refer to Rulemaking (R.)18-12-005, PG&E's 2022 Access and Functional Needs (AFN) Plan for Public Safety Power Shutoff (PSPS) Support, (January 31, 2022). See Appendix E.

170 R.18-12-005, PG&E's Access and Functional Needs (AFN) Plan for Public Safety Power Shutoff (PSPS) Support, (January 31, 2023). See Appendix E.

the tactics described in Table 8-60 below to increase public awareness about emergency preparedness.

TABLE 8-60:
PG&E'S COMMUNITY OUTREACH AND EDUCATION 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.	IHSS, Regional 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
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

TABLE 8-60:
PG&E'S COMMUNITY OUTREACH AND EDUCATION 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
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.	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	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

8.5.3 Engagement With Access and Functional Needs Populations

In this section, the electrical corporation must provide an overview of its process for understanding, evaluating, designing, and implementing wildfire and PSPS risk mitigation strategies, policies, and procedures specific to AFN customers across its territory. The electrical corporation must also report, at a minimum, 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.*
- *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 Section 8.5.5 should include high-level strategies, policies, programs, and procedures for outreach, engagement in the development and implementation of the AFN-specific risk mitigation strategies, and ongoing feedback practices.*

Reference the Utility Initiative Tracking ID where appropriate.

Utility Initiative Tracking ID: PS-05; PS-06

Key Access and Functional Needs Demographics, Distribution, and percent of Total Customer Base

It is important for us to identify vulnerable AFN customers to ensure that we provide them the information and help that they need to stay safe during a PSPS event. PG&E identifies customers and/or households that are considered AFN using the following data from our internal databases.

TABLE PG&E-8.5.3-1:
IDENTIFYING AFN CUSTOMERS

Customer Group	Number of Customers
Customers enrolled in the MBL program; .	276,626
Residential customers on tiered rate plans;[(a)]	Redundant with MBL
Energy Savings Assistance (ESA) Program participants;[(b)]	12,343
Customers enrolled in California Alternative Rates for Energy (CARE) Program or Family Electric Rate Assistance (FERA);	37,058
Customers that self-identify to receive an in-person visit before disconnection for non-payment (e.g., vulnerable);	16,892
Customers that self-identify as having a person with a disability in the household (e.g., disabled);	45,832
Customers who self-select to receive utility communications in non-standard format (e.g., in braille or large print); and	922
Customers who indicate a non-English language preference.	1,571,171
In 2022, PG&E added six additional categories for which customers can self-identify including:	
Customers that self-identify as having a person in the household that uses durable medical equipment;	53,904
Customers that self-identify as having a person in the household that uses Assistive Technology;	9,316
Customers that self-identify as having a person in the household that has a hearing disability (e.g., deaf, or hard of hearing);	26,242
Customers that self-identify as having a person in the household that has a vision disability (e.g., Low Vision);	17,591
Customers that self-identify as having a person in the household that is blind; and	1,367
Customers that self-identify as having a person in the household that is 65+ years old.	82,766

(a) These customers receive an allotment of energy every month at the lowest price available on their rate, called the Baseline Allowance. Customers who are eligible for MBL receive an additional allotment of electricity and/or gas per month (approximately 500 kilowatt-hours of electricity and/or 25 therms of gas per month). This helps ensure that more energy to support qualifying medical devices is available at a lower rate.
(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 fourteen categories described above represent approximately 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 works hard to identify customer challenges and needs during a wildfire or outage event through several stakeholder forums and focus groups. PG&E describes specific challenges and needs in the Annual AFN Plan for PSPS Support. PG&E has identified our AFN customers during a Wildfire or PSPS event and reports this quarterly in the AFN Quarterly Progress Reports. Both the Annual AFN Plan for PSPS Support and the AFN Quarterly Progress Reports are available at the following link: www.pge.com/pspsreports.

People with Disabilities and Aging Council

Provides a forum for gathering information about the needs of the AFN populations related to emergency preparedness and to create solutions and identify resources to help these customers before, during, and after an event. The People with Disabilities and Aging Council is a diverse group of CBO leaders that supports people with developmental or intellectual disabilities, physical disabilities, chronic conditions, injuries, and older adult communities. The council meets quarterly to gather feedback and provide information on resources, services, and programs.

Joint IOU Statewide AFN Advisory Council

The Joint IOUs established the Statewide IOU 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:[171] 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 State Council on Developmental Disabilities, Disability Rights California, CFILC, Disability Rights Education and Defense Fund, California Governor's Office of Emergency Services, CPUC, Liberty Utilities, Bear Valley Electric, and Pacific Corp. 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 IOUs have created an AFN Core Planning team to develop the 2023 AFN Plan. PG&E and the AFN Core Planning team followed the six steps outlined by the Federal Emergency Management Agency (FEMA) Comprehensive Preparedness Guide (CPG).[172,173] We filed our 2023 AFN Plan on January 31, 2023.

Other Advisory Councils

PG&E will also continue to engage with and solicit feedback on wildfire and PSPS-related outreach from other existing advisory groups.

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171 A continuation of the AFN Panel Discussion included in the CPUC Joint IOU PSPS Workshop (March 29, 2021).

172 FEMA Developing and Maintaining Emergency Operations Plans CPG 101 6-Step Process. See Appendix E.

173 D.21-06-034. See Appendix E.

- Disadvantaged Communities Advisory Group: An advisory group that meets quarterly, led by the CPUC and California Energy Commission, with representatives from disadvantaged communities. The purpose of this group is to review and provide advice on proposed clean energy and pollution reduction programs and determine whether those proposed programs will be effective and useful in disadvantaged communities. PG&E engages with this group to provide information and gain input about wildfire mitigation activities, including PSPS.

- Low Income Oversight Board: A board established to advise the CPUC on low-income electric and gas customer issues and programs. PG&E also engages with this group 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 PSPS Regional Working Groups. Additionally, PG&E hosts local wildfire safety sessions with each county Office of Emergency Services (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 will continue to solicit input from 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

One of PG&E's highest priorities during wildfire-related emergencies is to protect the health and safety of our vulnerable/AFN customers and communities. PG&E conducts outreach related to emergency preparedness, provides enhanced notifications during PSPS events, and offers additional services and resources to these customers in advance of and during PSPS events—either directly or in partnership with CBOs.

During PSPS, MBL customers and SIV customers receive automated calls, texts, and e-mails at the same intervals as the general customer notifications. PG&E provides unique PSPS Watch and PSPS Warning notifications to MBL program customers and SIV customers. These customer segments also receive additional calls and texts at hourly intervals until the customer acknowledges the automated notifications by either answering the phone, responding to the text, or opening the e-mail. If acknowledgement is not received, a PG&E representative attempts to visit the customer's home to ensure the customer is aware of the upcoming PSPS (referred to as the "doorbell ring" process) while hourly notification retries continue. During the doorbell ring visit, if the customer requires assistance, the PG&E field representative will request resources from the AFN Strategy Lead in the EOC. If the customer does not answer the door, the representative leaves a door hanger at the home to indicate PG&E visited. The notification is considered successful if the customer is contacted in-person or a door hanger is left. 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.[174]

PG&E continues to deliver on our goal of making PSPS events less burdensome for our customers. We provide:

- Portable Battery Program: We work with CBOs to provide free portable backup battery solutions as well as mini-fridges and insulin cooler wallets for medications to MBL customers in Tier 2 and 3 HFTD or who are on EPSS-capable circuits that have experienced PSPS in 2021 or who were impacted by 5 or more EPSS outages in 2022. We will explore the transition of the Portable Battery Program to permanent battery solutions to help mitigate outages over a longer time-period than portable solutions for PG&E customers as reflected in our Objective PS-05. Additionally, we have set a target of providing new or replacement portable batteries to 12,000 PG&E customers at risk of PSPS or EPSS. This initiative is aligned to Target PS-06.

- Generator and Battery Rebate Program: We provide a $300 rebate to customers located in Tier 2 or 3 HFTDs or who are served by an EPSS circuit and were part of 2 or more PSPS events. Customers are eligible for an additional $200 rebate if enrolled in PG&E's CARE or FERA program.

- Backup Power Transfer Meter (BPTM): We install a BPTM device for customers who reside in Tier 2 or 3 HFTDs or who are served by an EPSS circuit. The BPTM device is a meter that is also a transfer switch that will automatically connect power to a generator when it detects the grid is offline and switch back to the utility once the grid 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.

- Fixed Power Solutions (FPS): A new initiative launched in 2022, FPS supports permanent, long-term backup power solutions for customers frequently impacted by PSPS and EPSS outages. These permanent solutions can help customers mitigate outages over a longer time horizon than portable solutions. We intend to significantly scale-up the FPS offering in 2023 and beyond—specifically, for residential battery storage—to help ensure that the risks of PSPS and EPSS are minimized for the most impacted customers.

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174 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.

We partner with several organizations to provide services during wildfires or PSPS outages. These partnerships include:

- 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 (see Table 8-59 List of Community Partners, in Section 8.5.2).

PG&E opens Community Resource Centers (CRC) during a PSPS event to provide customers with basic power and other needs. We describe our CRCs and the services we offer at them in Section 8.4.6. 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 the 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 and education and outreach about PG&E programs.

PG&E has an agreement 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. This agreement 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 will focus on outreach to at-risk customers, including those living in each IOU's HFRAs 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.

8.5.4 Collaboration on Local Wildfire Mitigation Planning

In this section, the electrical corporation must provide a high-level overview of its plans, programs, and/or policies for collaborating with communities on local wildfire mitigation planning (e.g., wildfire safety elements in general plans, community wildfire protection plans, local multi-hazard mitigation plans) within its service territory. 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, and tribal agencies 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):*
  - *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. Table 8-61 provides an example of the minimum acceptable level of information. Reference the Utility Initiative Tracking ID where appropriate.*
- *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. Table 8-62 provides an example of the minimum acceptable level of information.*

PG&E understands this question is asking us to describe how we coordinate with agencies related to wildfire plans developed by local jurisdictions. PG&E is not the lead authority for wildfires, and we cannot require local jurisdictions to create wildfire plans. However, if requested, PG&E reviews and provides feedback on local wildfire plans, specifically as it relates to electric and gas impacts during a wildfire.

Table 8-61 in Appendix F lists more than 600 engagements conducted by PG&E's Public Safety Specialists in 2022 that focused on emergency preparedness. Our Public Safety Specialists met with local fire departments, emergency services organizations, CAL FIRE, local governments, and the US Forest Service to discuss topics related to wildfire preparedness such as Pub. Util. Code 956.5 (referred to as Assembly Bill 56 (AB56) in Appendix E) and to review contingency plans with local fire departments for emergencies involving interstate transmission and distribution lines within the jurisdiction of the local fire department. Other topics include PG&E's Preventing and Mitigation Fires While Performing PG&E Work (TD-1464S), OES coordination and evacuation planning.

PG&E develops our annual WMP focused on preventing wildfires due to electrical assets or equipment and shares its plans with local jurisdictions for feedback. See Section 8.4.3.1 for more information about PG&E's outreach.

Table 8-62 lists key gaps and limitations in collaborating on local wildfire mitigation planning.

**TABLE 8-61:
COLLABORATION IN LOCAL 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
Note: See complete Table 8-61 in Appendix F.			

**TABLE 8-62:
KEY GAPS AND LIMITATIONS IN COLLABORATING ON
LOCAL 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.

8.5.5 Best Practice Sharing with Other Electrical Corporations

In this section, the electrical corporation must provide a high-level overview of its policy for sharing best practices and collaborating with other electrical corporations on technical and programmatic aspects of its WMP Program. The narrative must be no more than one page.

In addition, the electrical corporation must provide a list in tabular form of relevant electrical corporations and other entities it has shared or collaborated or intends to continue to share or collaborate or begin sharing or collaborating, with on best practices for technical or programmatic aspects of its WMP Program.

For each entity, the best practice subject, date(s) of collaboration, whether the collaboration is technical or programmatic, list of electrical corporation partners, a description of the best practice sharing/collaborative activity with a reference, and any outcomes from that sharing or activity.

Reference the Utility Initiative Tracking ID where appropriate.

The overview and table must be no longer than two pages in the main body of the WMP. The full table can be included as an appendix as needed.

Table 8-63 provides an example of the minimum acceptable level of information.

Policy for Sharing Best Practices:

PG&E shares information related to best practices for the technical and programmatic aspects of our wildfire mitigation programs with the other California IOUs and other electrical corporations. Since we understand how important it is to work with other utilities and share best practices, we look for and take advantage of these opportunities. Sharing best practices takes on different forms from participating in technical working groups as part of regulatory proceedings to more informal calls and meetings among our Subject Matter Experts and their counterparts at other electric utilities. PG&E encourages all our team members to participate in these activities.

Sharing best practices is an opportunity for us to learn from other utilities and incorporate new practices and procedures into our wildfire mitigation programs. It helps us meet our goal to continuously improve how we mitigate ignition risk and reduce customer impacts due to wildfires and wildfire-related outages.

In Table 8-63 below we provide an example of who we share best practices with, the type of information shared, and the outcomes of that exchange. The full table exceeds the page limit and is provided in Appendix F.

TABLE 8-63:
SHARING BEST PRACTICES WITH OTHER UTILITIES

Best Practice Subject	Dates of Collaboration	Technical or Programmatic	Corporation Partner(s)	Description of Best Practice Sharing or Collaborating	Outcome
Covered Conductor Effectiveness Study	2021-present	Technical	• PG&E • Southern California Edison Company (SCE) • San Diego Gas & Electric Company (SDG&E) • PacifiCorp • Bear Valley • Liberty Utilities	Coordinate to develop a consistent approach to evaluating the long-term risk reduction and cost-effectiveness of covered conductor deployment, including: • The effectiveness of covered conductor in the field in comparison to alternative initiatives; and • How covered conductor installation compares to other initiatives in its potential to reduce PSPS risk.	Developed Joint IOU Failure Modes and Effects Analysis (FMEA) for covered conductors. Benchmarking report for historic testing informing performance of Covered Conductor. Collaborative and complementary testing reports from SCE and PG&E, with SDG&E testing report expected in 2023. Continue work on lessons learned in 2023.

Note: The full table can be found in Appendix F.

PACIFIC GAS AND ELECTRIC COMPANY

2023-2025 WILDFIRE MITIGATION PLAN

SECTION 9

PUBLIC SAFETY POWER SHUTOFF

9 Public Safety Power Shutoff

9.1 Overview

In Sections 9.1-*9.7 of the Wildfire Mitigation Plan (WMP), the electrical corporation must:*

- *Provide a high-level overview of key Public Safety Power Shutoff (PSPS) statistics;*
- *Identify circuits that have been frequently de-energized and provide measures for how the electrical corporation will reduce the need for, and impact of, future PSPS implementation on those circuits;*
- *Describe expectations for how the electrical corporation's PSPS Program will evolve over the next 3 and 10 years;*
- *Describe any lessons learned for PSPS events occurring since the electrical corporation's last WMP submission; and*
- *Describe the electrical corporation's protocols for PSPS implementation.*

Our objective when initiating a PSPS event is to keep our customers safe. High winds can cause tree branches and debris to contact energized electric lines, damage our equipment, and cause a wildfire. As a result, we may need to turn off power during severe weather to help prevent wildfires. We know that losing power disrupts lives, that is why we are working year-round to make our system safer and more resilient and reduce the impact of PSPS for our customers and communities.

Pacific Gas and Electric Company (PG&E) remains committed to executing our PSPS Program in a manner that complies with California Public Utilities Commission (CPUC) guidelines in accordance with Resolution ESRB-8, D.19-05-042, D.20-05-051, and D.21-06-034.

9.1.1 Key PSPS Statistics

In this section, the electrical corporation must include a summary table of PSPS event data. These data must be calculated from the same source used in the Geographic Information System (GIS) data submission (i.e., they should be internally consistent). If it is not possible to provide these data from the same source, the electrical corporation must explain why. Table 9-1 provides an example of the minimum acceptable level of information for a summary of PSPS event data.

Table 9-1 below lists the 2022 PSPS event data. This information was gathered using the same source used in the GIS data submission. For additional PSPS metrics, please see Table 10 of the 2023 QDR.

TABLE 9-1:
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)]	–	–	–	–

(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. Only for events in which de-energization ultimately occurred.

(b) Circuits De-energized: 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 number 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) In 2022, we did not have an event where de-energization was initiated.

9.1.2 Identification of Frequently De-Energized Circuits

Public Utilities Code Section 8386(c)(8) requires the Identification of circuits that have frequently been de-energized pursuant to a PSPS event to mitigate the risk from wildfire and the measures taken, or planned to be taken, by the electrical corporation to reduce the need for, and impact of, future PSPS of those circuits, including, but not limited to, the estimated annual decline in circuit PSPS and PSPS impact on customers, and replacing, hardening, or undergrounding any portion of the circuit or of upstream transmission or distribution lines." To comply, the electrical corporation is required to populate Table 9-2 *and provide a map showing the frequently de-energized circuits.*

The map must show the following:

- *All circuits listed in Table 9-2, colored or weighted by frequency of PSPS; and*
- *High Fire Threat District (HFTD) Tiers 2 and 3 contour overlays.*

Examples of the minimum acceptable level of information is provided in Table 9-2*.*

Utility Initiative Tracking ID: PS-01; PS-02; PS-03; PS-04

For the list of frequently de-energized circuits,[175] PG&E identified circuits de-energized three or more times in any calendar year from 2018 to 2022. These circuits are listed in Table 9-2 below (see Appendix F for complete Frequently De-energized Circuit Table). This table also includes the mitigation measures taken, or planned to be taken, to reduce the likelihood of PSPS on those circuits. These mitigations include:

- Past Mitigations;
- Grid Hardening;
- PSPS Protocols;
- Sectionalizing Devices;
- Temporary Generation;
- Transmission Tags;
- Transmission Island;
- Transmission Segmentation;

[175] PG&E updated the list of frequently de-energized list from the 2022 WMP by combining the October 26, 2019 event and the October 29, 2019, event into one October 26, 2019 event to align with the Table 10 data tables. This change removed 17 Transmission circuits from the minimum three de-energizations that occurred between 2018-2022. No changes were made to the listed Distribution circuits.

- Vegetation Management (VM);
- Planned Mitigations;
- Undergrounding; and
- Motor Switch Operator (MSO) Replacement.

PG&E's PSPS Protocols were updated in 2021 as compared to the 2020 and 2019 PSPS Protocols. Based on our updated 2021 PSPS Protocols, some of the circuits below would not have been de-energized three or more times in any calendar year from 2019 to 2022. These circuits are noted below as "mitigated with PSPS Protocols." Additionally, some planned mitigations are still being analyzed so we cannot identify the impact of those plans on a per circuit basis.

We provide an estimated annual decline in customer impact on PSPS in Areas for Continued Improvement ACI PG&E-22-35. The analysis uses the most recent five years lookback to quantify the expected customer impacts of our planned mitigations. Additional analysis will need to be performed to estimate the annual decline in circuits impacted by PSPS.

Undergrounding may mitigate PSPS activity in areas where lines are relocated underground because the lines themselves do not 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. For additional details on undergrounding, see Section 8.1.2.2.

TABLE 9-2:
LIST OF FREQUENTLY DE-ENERGIZED CIRCUITS

Entry Number	ID of Circuit	Circuit Name	Transmission (Tx) / Distribution (Dx)	County	Dates of Outages	Number of Customers Served by Circuit (as of December 1, 2022)	Number of Customers affected	Measures Taken, or Planned to Be Taken, to Reduce the Need for and Impact of Future PSPS of Circuit
1	152101101	ALLEGHANY 1101	Dx	SIERRA	10/9/2019	1,036	1,043	• 1 Sectionalizing device added or replaced • Temporary Generation deployed that benefited 994 customers
					10/23/2019		1,038	
					10/26/2019		1,037	
					9/7/2020		1,028	
					9/27/2020		1,032	
					10/14/2020		957	
					10/25/2020		1,033	
2	152101102	ALLEGHANY 1102	Dx	NEVADA	10/9/2019	151	151	• 0.4 miles of overhead hardening completed
					10/23/2019		151	
					10/26/2019		152	
					9/7/2020		151	
					9/27/2020		153	
					10/25/2020		153	
3	163561101	ALPINE 1101	Dx	ALPINE	10/9/2019	278	278	• Mitigated by PSPS protocols
					10/23/2019		278	
					10/26/2019		277	
					9/7/2020		276	
					9/27/2020		278	
					10/25/2020		278	
4	163561102	ALPINE 1102	Dx	ALPINE	10/9/2019	306	303	• Mitigated by PSPS protocols
					10/23/2019		303	
					10/26/2019		304	
					9/7/2020		303	
					9/27/2020		303	
					10/25/2020		304	

TABLE 9-2:
LIST OF FREQUENTLY DE-ENERGIZED CIRCUITS
(CONTINUED)

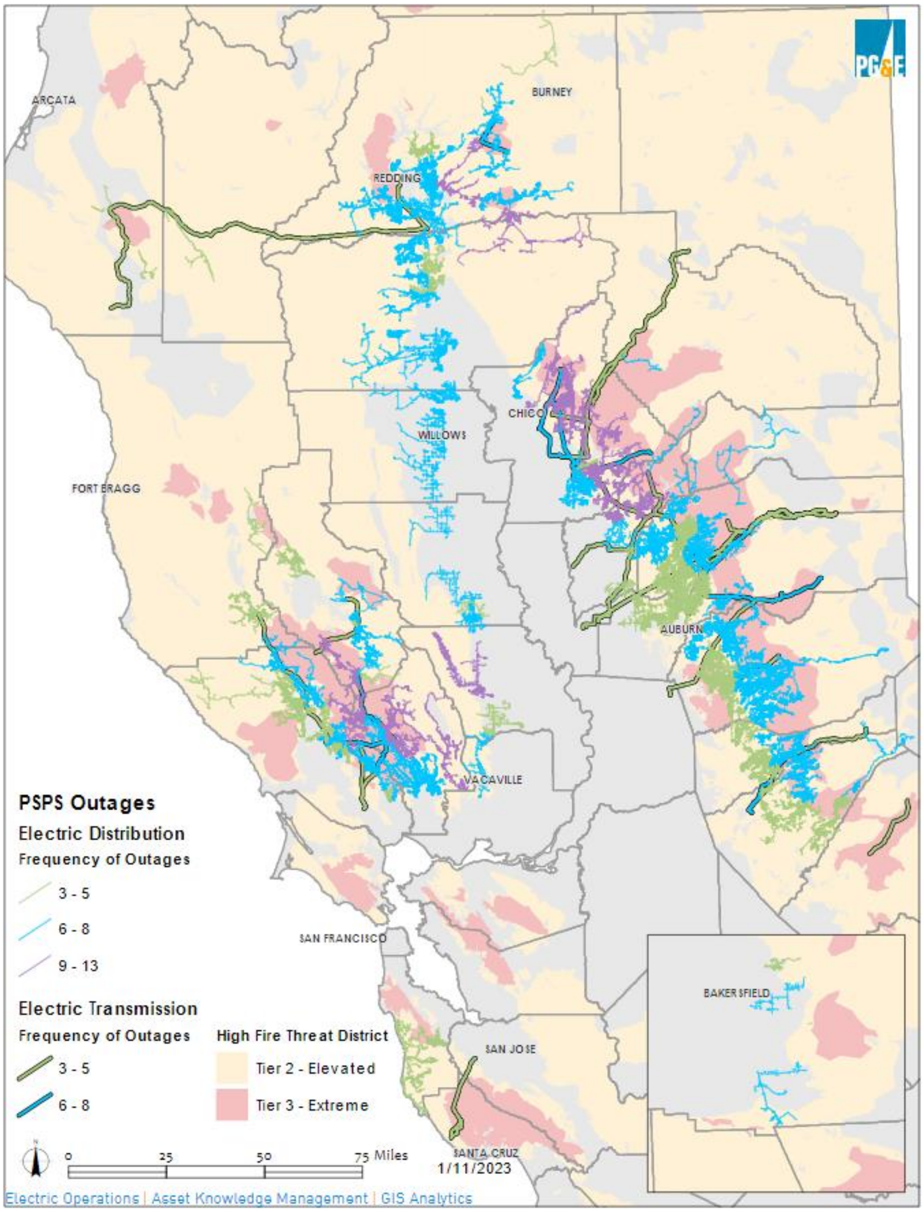
Entry Number	ID of Circuit	Circuit Name	Transmission (Tx) / Distribution (Dx)	County	Dates of Outages	Number of Customers Served by Circuit (as of December 1, 2022)	Number of Customers affected	Measures Taken, or Planned to Be Taken, to Reduce the Need for and Impact of Future PSPS of Circuit
5	103261103	ANDERSON 1103	Dx	SHASTA	10/9/2019	895	886	• Sectionalizing devices added or replaced
					10/26/2019		886	
					11/20/2019		436	
					10/21/2020		437	
					10/25/2020		438	
					8/17/2021		68	
					10/11/2021		68	
6	42861101	ANNAPOLIS 1101	Dx	SONOMA	10/9/2019	223	219	• Mitigated by PSPS protocols
					10/23/2019		9	
					10/26/2019		218	
					10/25/2020		222	

Notes: The 2019 temporary generation mitigation data does not include customers mitigated because some data such as temporary microgrid circuits was not recorded at the circuit level. Additionally, in some examples the customer count that was energized by temporary microgrids via temporary generation may have combined customer count without separate count by circuit.

This table includes circuits de-energized three or more times in any calendar year from 2019-2022. For the full list of frequently de-energized circuits see Appendix F.

Figure PG&E-9.1.2-1[176] below shows de-energized circuits, color-weighted by PSPS frequency, with HFTD Tier 2 and 3 contour overlays.

FIGURE PG&E-9.1.2-1:
DE-ENERGIZED CIRCUITS BY FREQUENCY WITH HFTD CONTOUR OVERLAYS



Note: Circuits shown in the map represent the entire line and do not account for sectionalization.

176 For additional map viewing instructions, please refer to Appendix C.

9.1.3 Objectives

Each electrical corporation must summarize the objectives for its 3-year and 10-year plans to reduce the scale, scope, and frequency of PSPS events. These summaries must include the following:

- *Identification of which initiative(s) in the WMP the electrical corporation is implementing to achieve the stated objective, including Utility Initiative Tracking IDs;*
- *Reference(s) to applicable codes, standards, and best practices/guidelines and an indication of whether the electrical corporation exceeds an applicable code, standard, or regulation;*
- *Method of verifying achievement of each objective;*
- *A completion date for when the electrical corporation will achieve the objective; and*
- *Reference(s) to the WMP section(s) or appendix, including page numbers, where the details of the objective(s) are documented and substantiated.*

This information must be provided in Table 9-3. Example of PSPS Objectives (3-year plan) for the 3-year plan and Table 9-4. Example of PSPS Objectives (10-year plan) for the 10-year plan. Examples of the minimum acceptable level of information are provided below.

We are evaluating if Fire Potential Index (FPI) and the Ignition Probability Weather (IPW) updates can reduce the scale, scope, and frequency of PSPS events. See Table 8-21 in Section 8.3.1.1 and Section 8.3.6 for more information.

- Table 9-3 Information Summary: In Table 9-3 and Table 9-4 we are providing the objective name (Objective Name), a description of the objective (Objective Description), the anticipated outlook of the objective (3-Year/10-Year Outlook), the planned due date for the objective (Completion Date), the applicable Initiative Tracking ID (Initiative Tracking ID), "Applicable Regulations, Codes, Standards, and Best Practices", "method of verification", and "section and page #" references. As noted in Section 7.2.1, "Applicable Regulations, Codes, Standards, and Best Practices," "method of verification," and "section and page #" columns are not a part of the objective. Instead, the controlling objective information is in the "Objective Description" and "Completion Date" columns.
- Reporting: Unless changed through Office of Energy Infrastructure Safety's (Energy Safety) Change Order process, PG&E will use the objectives in Table 9-3 and Table 9-4 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 2023-2025 WMP, we discuss current plans for wildfire-related activities beyond the objectives in Table 9-3 and Table 9-4. The timing and scope of these additional activities and work may change. We will not be reporting on these plans or activities in our QDR, QN, or ARC because they are not

objectives but are descriptions of plans and activities in our 2023-2025 WMP to provide a complete picture of our wildfire mitigation activities.

- External Factors: All objectives in the below Table 9-3 and Table 9-4 are subject to External Factors which represent reasonable circumstances which may impact execution against objectives including, but not limited to: physical conditions, landholder refusals, environmental delays, 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 ID: We are including Initiative Tracking IDs in each section that has associated targets and objectives. Table 9-3 and Table 9-4 display the Tracking IDs we are implementing to tie the objectives to the narratives and initiatives in the WMP. The Initiative Tracking IDs will also be used for reporting in the QDR.

TABLE PG&E-9-3:
PSPS INITIATIVE OBJECTIVES (3-YEAR PLAN)

Objective Name	Objective Description	Applicable Initiative(s), Tracking ID(s)	Applicable Regulations, Codes, Standards, and Best Practices (See Note)	Method of Verification (i.e., program)	Completion Date	Reference (Section and Page #)
Evaluate enhancements for the PSPS Transmission guidance	Evaluate enhancements for the PSPS Transmission guidance to enhance focus of PSPS events.	PS-01	Industry best practice across California utilities is to run and improve their own models.	Documentation on evaluation of update to PSPS guidance	12/31/2025	Section 9.2.1 Page 766
Evaluate incorporation of approved IPW enhancements into the PSPS Distribution guidance	Evaluate incorporation of approved IPW enhancements into the PSPS Distribution guidance to enhance focus of PSPS events.	PS-02	D.19-05-042 and OIR 18-12-005 and Revision Notice 22-12 from 2022 WMP, industry best practice across California utilities is to run and improve their own models.	Documentation on evaluation of update to PSPS guidance	12/31/2025	Section 9.2.1 Page 766

TABLE PG&E-9-4:
PSPS INITIATIVE OBJECTIVES (10-YEAR PLAN)

Objective Name	Objective Description	Applicable Initiative(s), Tracking ID(s)	Applicable Regulations, Codes, Standards, and Best Practices (See Note)	Method of Verification (i.e., program)	Completion Date	Reference (Section and Page #)
Evaluate enhancements for the PSPS Transmission guidance	Evaluate enhancements for the PSPS Transmission guidance to enhance focus of PSPS events.	PS-03	Industry best practice across California utilities is to run and improve their own models.	Documentation on evaluation of update to PSPS guidance	12/31/2032	Section 9.2.1 Page 771
Evaluate incorporation of approved IPW enhancements into the PSPS Distribution guidance	Evaluate incorporation of approved IPW enhancements into the PSPS Distribution guidance to enhance focus of PSPS events.	PS-04	D.19-05-042 and OIR 18-12-005 and Revision Notice 22-12 from 2022 WMP, Industry best practice across California utilities is to run and improve their own models.	Documentation on evaluation of update to PSPS guidance	12/31/2032	Section 9.2.1 Page 771
Evaluate the transition of the Portable Battery Program to permanent battery solutions	Evaluate the transition of the Portable Battery Program to permanent battery solutions for PG&E customers at risk of PSPS or EPSS, focusing on but not limited to AFN, MBL, and self-identified vulnerable populations.	PS-05	CPUC R.12-11-005, D.19-09-027, CPUC R.12-11-005, D.20-01-021	Documentation of the assessment for transitioning to permanent battery solutions	12/31/2032	Section 8.5.3 Page 742

9.1.4 Targets

Initiative targets are forward-looking quantifiable measurements of activities identified by each electrical corporation in its WMP. Electrical corporations will show progress toward completing targets in subsequent reports, including QDRs and WMP Updates.

The electrical corporation must list all targets it uses to track progress on reducing the scope, scale, and frequency of PSPS for the three years of the Base WMP. Energy Safety's Compliance Assurance Division and third parties must be able to track and audit each target. For each initiative target, the electrical corporation must provide the following:

- *Utility Initiative Tracking IDs;*
- *Projected targets for the three years of the Base WMP and relevant units;*
- *The expected "x%" risk impact for each of the three years of the Base WMP. The expected "x%" risk impact is the expected percentage risk reduction per year, as described in Section 7.2.2.2; and*
- *Method of verifying target completion.*

The electrical corporation's targets must provide enough detail to effectively inform efforts to improve the performance of the electrical corporation's initiatives aimed at reducing the scope, scale, and frequency of its PSPS events.

Table 9-5 is an example of the minimum acceptable level of information.

To reduce the scale, scope, and frequency of PSPS outages, PG&E's plans include the following initiatives:

- Undergrounding (see Section 8.1.2.2): Installing 10,000 miles of distribution powerlines underground in and near high fire-risk areas.
- MSO Device Replacements (see Section 8.1.2.8): PG&E is replacing existing MSO devices with suitable load-break capable devices. This will allow PG&E to use the new devices during PSPS events to better sectionalize circuits, thus mitigating the number of customers impacted during PSPS outages.

See Section 8.1.1.2 for undergrounding and MSO replacement Targets.

- Table 9-5 Information Summary: In Table 9-5, we are providing the target name (Target Name), the applicable Initiative Tracking ID (Initiative Tracking ID) and a description of the Target for each applicable year (2023 Target & Unit, 2024 Target & Unit, 2025 Target & Unit), the "% Risk Impact" for each respective year, and the method of verification. As noted in Section 7.2.1, the % Risk Impact and method of verification columns are not a part of the Target. Instead, the controlling target

- Utility Initiative Tracking ID: We are including Initiative Tracking IDs in each section that has associated targets and objectives. Table 9-5 displays the Tracking IDs we are implementing to tie the targets to the narratives and initiatives in the WMP. The Initiative Tracking IDs will also be used for reporting in the QDR.

- Reporting: Unless changed through Energy Safety's Change Order process, PG&E will use the Targets in Table 9-5 for quarterly compliance reporting including the QDR, QN, and the ARC. It is also important to note that throughout this 2023-2025 WMP, we discuss current plans for wildfire-related activities in addition to the Targets in Table 9-5. The timing and scope of these additional activities and work may change. We will not be reporting on these plans or activities in our QDR, QN, or ARC because they are not Targets but are descriptions of plans and activities in our 2023-2025 WMP to provide a complete picture of our mitigation activities.

- External Factors: All targets in the below Table 9-5 are subject to External Factors which represent reasonable circumstances which may impact execution against targets including, but not limited to, physical conditions, landholder refusals, environmental delays, 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.

- High Fire Threat District (HFTD), High Fire Risk Area (HFRA), Buffer Areas: Unless stated otherwise, all initiative work described in Table 9-5 involves work or audits on units or equipment located in, traversing, energizing, or protecting units or equipment in HFTD, HFRA, or Buffer Zone areas.

TABLE PG&E-9-5:
PSPS TARGETS

Target Name	Initiative Activity Tracking ID	Reference Section	2023 Target & Unit	x% Risk Impact 2023	2024 Target & Unit	x% Risk Impact 2024	2025 Target & Unit	x% Risk Impact 2025	Method of Verification
Provide 12,000 cumulative new or replacement portable batteries to PG&E customers at risk of PSPS or EPSS, focusing on but not limited to AFN, MBL, and self-identified vulnerable populations	PS-06	Section 8.5.3	Provide 4,000 cumulative new or replacement portable batteries to PG&E customers	N/A	Provide 4,000 cumulative new or replacement portable batteries to PG&E customers	N/A	Provide 4,000 cumulative new or replacement portable batteries to PG&E customers	N/A	Annual tracking and reporting
Reduce PSPS impacts by ~55k customer events (3.4%) for 2023-2025 period by completing planned Wildfire mitigation projects including but not limited to MSO switch replacements and undergrounding[(a)]	PS-07	Section 9.1.5 ACI PG&E-22-35	15,000 customer events based on Wildfire mitigation projects including but not limited to MSO replacements and Undergrounded miles planned for 2023	N/A	33,000 customer events based on Wildfire mitigation projects including but not limited to MSO replacements and Undergrounded miles planned for 2023-2024	N/A	55,000 customer events based on Wildfire mitigation projects including but not limited to MSO replacements and Undergrounded miles planned for 2023-2025	N/A	Annual/ quarterly reporting and tracking

(a) Target reduction of PSPS impacts by customers are dependent on completion of planned MSO replacements and undergrounded miles each year.

9.1.5 Performance Metrics Identified by the Electrical Corporation

Performance metrics indicate the extent to which an electrical corporation's WMP is driving performance outcomes. Each electrical corporation must:

- *List the performance metrics the electrical corporation uses to evaluate the effectiveness of reducing reliance on PSPS.*

For each of these performance metrics listed, the electrical corporation must:

- *Report the electrical corporation's performance since 2020 (if previously collected);*
- *Project performance for 2023-2025; and*
- *List method of verification.*

The electrical corporation must ensure that each metric's name and values are the same in its WMP reporting as its QDR reporting (specifically, QDR Table 2 and QDR Table 3). Metrics listed in this section that are the same as performance metrics required by Energy Safety and reported in QDR Table 2 (Performance Metrics) must match those reported in QDR Table 2. Metrics listed in this section that are not the same as any of the performance metrics identified by Energy Safety and reported in QDR Table 2 must match those reported in QDR Table 3.

The electrical corporation must:

- *Summarize its self-identified performance metric(s) in tabular form; and*
- *Provide a brief narrative that explains trends in the metrics.*

Table 9-6 provides an example of the minimum acceptable level of information.

In addition to the table, the electrical corporation must provide a narrative (two pages maximum) explaining its method for determining its projected performance on these metrics (e.g., PSPS consequence modeling, retrospective analysis).

Utility Initiative Tracking ID: PS-07

PG&E uses many performance metrics to evaluate the effectiveness of our PSPS Program. Some of these metrics include tracking the frequency, scope, and duration of PSPS events, as well as customer hours of PSPS per Red Flag Warning Overhead (RFW OH) circuit mile days. Table 9-6 provides historic recorded data and an analysis of the past 5 years of weather data as a basis for the forecasted metrics.

Performance metrics related to frequency, scope, and duration of PSPS events are largely weather dependent and customer impact will fluctuate depending on the meteorological conditions and grid configuration at the time of each event. The inclusion of the customer hours of PSPS per RFW OH circuit mile day metric is intended to normalize the customer hours using RFW to remove the unpredictability of weather in the metric and demonstrate improvements to the PSPS Program.

Notifying customers prior to initiation of PSPS event ensures customers are aware of the potential outages and the resources available to them. The metric “number of customers notified prior the initiation of PSPS event” is largely weather dependent as this metric will correlate with the frequency, scope, and duration of PSPS events. Using our 2023 workplans for undergrounding and MSO replacements, PG&E projected PSPS metrics into 2023 and keeps those values static for 2024-2025. PG&E anticipates continued improvement from 2023-2025 which includes reducing PSPS impact of approximately 55,000 customers. This reduction calculation was built using planned MSO replacement projects and undergrounding projects based on the 2022 PSPS guidance and protocols as described in the 2023 Wildfire Mitigation Plan when applied to the 5-year lookback of historic weather and simulated PSPS events as calculated in Table 22-35-1, not on future weather events. This initiative is aligned to Target PS-07.

PG&E has also outlined the past and forecasted PSPS metrics in Table 10 of the QDR.

TABLE 9-6:
PROPOSED PSPS PERFORMANCE METRICS RESULTS BY YEAR

Performance Metrics[e]	2020	2021	2022	2023 Projected	2024 Projected	2025 Projected	Method of Verification (e.g., Third-Party Evaluation, QDR)
Frequency of PSPS Events	6	5	0	4	4	4	QDR[a]
Total Number of Customers Impacted by PSPS	649,685	80,319	0	317,151	313,527	309,138	QDR[b]
Duration of PSPS Events (in customer hours)	22.3 million	2.5 million	0	12.3 million	12.2 million	12.0 million	QDR[c]
Customer Hours of PSPS per RFW OH Circuit Mile Day	25.1	6.1	0	25.1	24.8	24.5	QDR[d]

(a) QDR Table 10, QDR No. 1a.

(b) QDR Table 10, QDR No. 4a.

(c) QDR Table 10, QDR No. 1c.

(d) QDR Table 10, QDR No. 1c/5-year historical average RFW OH Mile Days (not identified in Table 10).

(e) Based on the required metrics that are reported in the QDR, we calculated the projected metrics based on a single year average of the five-year lookback. However, in our target PS-07, we measured based on the entire five-year lookback. Data in this table cannot be used to replicate the projected mitigated customers in Target PS-07 due to following reasons: first, projected mitigated customers in Target PS-07 is calculated based on the entire five-year (2018-2022) lookback, whereas the 2023-2025 projected customer counts in this table are calculated from using a single average year using the five-year (2018-2022) lookback (for QDR purposes). Secondly, Target PS-07 is calculated based on the cumulative benefit of 2023-2025 planned WMP mitigations. This table displays 2023-2025 projected customer counts, and the 2023 projected customer count already incorporates the benefits of 2023 planned WMP mitigations. This metric-does not include what the customer count would have been without any 2023-2025 planned WMP mitigations; this means taking the difference of the 2023 projected customer count and the 2025 projected customer count would only show the mitigation benefits of 2024 and 2025 planned WMP mitigations and would not account for the mitigation benefit of 2023 planned WMP mitigations. As a result, this would underrepresent the benefits of 2023-2025 planned WMP mitigations compared to Target PS-07.

9.2 Protocols on PSPS

The electrical corporation must describe its protocols on PSPS implementation including:

- *Risk thresholds, such as wind speed (WS), FPI, and so on, and a decision-making process that determine the need for a PSPS. Where the electrical corporation provides this information in another section of the WMP, it must provide a cross-reference here rather than duplicating responses;*
- *Method used to compare and evaluate the relative consequences of PSPS and wildfires;*
- *Outline of the strategic decision-making process for initiating a PSPS, such as, a decision tree. Where the electrical corporation provides this information in another section of the WMP, it must provide a cross-reference here rather than duplicating responses; and*
- *Protocols for mitigating the public safety impacts of PSPS, including impacts on first responders, health care facilities, operators of telecommunications infrastructure, and water electrical corporations/agencies.*

9.2.1 Risk Thresholds (e.g., WS, FPI, etc.) and Decision-Making Process That Determine the Need for a PSPS.

Utility Initiative Tracking ID: PS-01; PS-02; PS-03; PS-04

PG&E carefully monitors data from multiple sources to determine if conditions require an outage for public safety. These sources include weather data and federal forecasts, including:

- High-resolution forecasts of the FPI Model, IPW Model and Technosylva fire spread simulations;
- Weather model forecast data from external sources, including American, European, and Canadian weather models;
- Red Flag Warnings from the National Weather Service;
- Real-time data from weather stations;
- Live feeds from our wildfire cameras;
- High-risk forecasts of Significant Fire Potential from the Geographic Area Coordination Centers;
- Fire weather outlooks from the Storm Prediction Center, which is part of the National Weather Service and National Oceanic and Atmospheric Administration; and

- Information received on interagency conference calls during high-risk periods.

Steps for Determining if a PSPS is Necessary

Distribution PSPS Decision-Making

PG&E starts with our distribution system when deciding whether to turn off power for safety. The distribution powerlines are closer to communities and are generally more susceptible to dry, windy weather threats. We use 10+ years of PG&E high-resolution climate data to help quantify the wildfire risk and potential impacts of PSPS. This process is shown in Figure PG&E-9.2.1-1.

FIGURE PG&E-9.2.1-1:
VISUAL REPRESENTATION OF DISTRIBUTION PSPS DECISION-MAKING

Steps for determining if a PSPS is necessary

When determining whether to turn off power for safety, we start with the distribution system. These powerlines are closer to communities and are generally more susceptible to dry, windy weather threats. We use 10 years of PG&E high-resolution climate data to help understand wildfire risk and potential customer impacts of PSPS.

STEP 1

If all of the minimum fire conditions are met...

High fire potential | Low relative humidity | High wind speeds | Low fuel moisture

STEP 2

...we conduct an in-depth review of fire risk using three separate measures:

A. Catastrophic Fire Probability
PG&E uses machine learning to assess the likelihood of equipment failure during a given weather event and the risk of catastrophic wildfire if a failure occurs. This model uses a combination of the IPW Model and the FPI Model.

B. Catastrophic Fire Behavior
Even if the probability of a powerline or equipment failure is unlikely, we may still turn off power where the consequence of a wildfire would be extreme.

C. Vegetation and Electric Asset Criteria Considerations
We identify areas where tree or electric compliance issues may increase the risk of ignition.

STEP 3

If any of the three measures in Step 2 are met, we turn off power for safety.

Determining the power outage area

Each of the three measures is evaluated within a small geographic area (four square kilometers). If any of the measures are met, circuits within that area are de-energized. Because powerlines travel across long distances, customers outside the affected area may also be impacted.

The following thresholds are taken into consideration when evaluating minimum fire potential conditions:

- Sustained WS above 19 miles per hour;
- Dead fuel moisture (DFM) 10 hour less than 9 percent;[177]
- DFM 100-hour, 1,000 hours less than 11 percent;[178]
- Relative Humidity (RH) below 30 percent;
- Herbaceous live fuel moisture below 65 percent;
- Shrub (Chamise) Live Fuel Moisture below 90 percent; and
- FPI above 0.7.

We do not use WS thresholds on a circuit basis as a gauge of outage or ignition probability.

In addition to assessing the areas that meet minimum fire potential conditions, PG&E conducts an in-depth review of fire risk using three separate measures: (1) Catastrophic Fire Probability (CFP), (2) Catastrophic Fire Behavior (CFB), and (3) Vegetation and Electric Asset Criteria Considerations.

Catastrophic Fire Probability

The CFP Model is the primary method used to determine if PSPS is necessary. This model combines the probability of fire ignitions due to weather impacting the electric system with the probability that a fire will be catastrophic if it starts. The CFP is derived by combining outputs from our FPI and the IPW Models.

<u>FPI Model</u>

The FPI Model determines the probability that a fire will become large or catastrophic, which is considered as part of the PSPS decision-making process. FPI is used as an hourly and daily tool to drive operational decisions to reduce the risk of utility-caused ignitions and wildfires.

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177 10-hour DFM represents the modeled moisture content in dead fuels in the 0.25 to 1-inch diameter class and the layer of the forest floor about one inch below the surface.

178 100-hour DFM represents the modeled moisture content of dead fuels in the 1 to 3-inch diameter class.

In 2019, and again in 2021, the FPI Model was enhanced with additional data and improved analytical capabilities. The current FPI Model combines the following information to predict the probability that an ignition could grow into a large and/or catastrophic fire:

- Fire weather parameters (WS, temperature, vapor pressure deficit);
- Fuel moisture data (dead fuel: dead grass and fallen branches; live fuel: grass and growing shrubs);
- Topography (terrain ruggedness, slope, wind-terrain alignment); and
- Fuel type data (grass, shrub, timber, or urban).

Ignition Probability Weather Model

The IPW Model is a machine learning model that uses ten or more years of weather data, outage, and historical ignition data to determine the likelihood of an outage for specific circuits during past weather events. The model also uses historical data to identify the outage causes. Some tracked causes include vegetation, structural failures, electrical malfunctions, and animal or third-party damage. The IPW model then analyzes the potential for that outage to be the source of an ignition. IPW learns from, and accounts for, changes on the grid from year-to-year.

To account for the hardening work performed, our IPW framework analyzes positive and negative changes in grid performance and reliability year-over-year and applies a timeweighted approach to weigh more recent years of learned performance more heavily in the final model output. The model learns the performance of local grid areas hour-by-hour based on the WS observed at that hour and if outages or ignitions occurred or not.

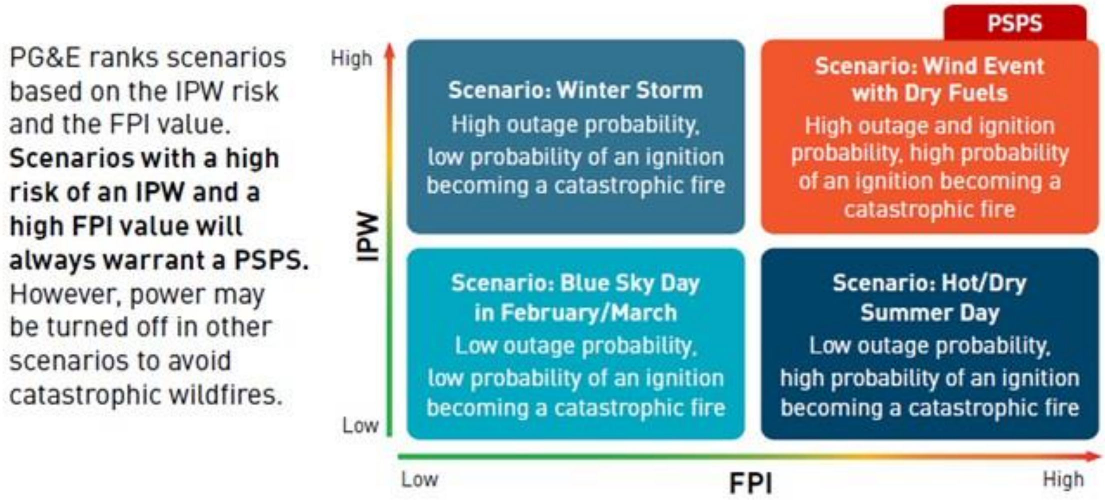
The guidance values PG&E uses when making a PSPS decision is a CFP_D (IPW*FPI) value greater than 9. This value was determined by running 70 PSPS sensitivity studies from 2008 through 2020. Through this 13-year historical analysis, PG&E evaluated the customer impacts by: (1) multiple dimensions (size, duration, frequency, repeat events, etc.), (2) the days when PSPS events would have occurred, and (3) whether historic fires caused by utility infrastructure could have been avoided due to the lines being de-energized in this analysis.

We will continue to explore if new features such as covered conductors and EPSS in the IPW model used for the PSPS Distribution guidance will provide benefits. This is reflected in our objectives PS-02 and PS-04.

Machine Learning and Tree Considerations

PSPS protocols use a machine learning model to include the potential for trees to strike the lines. This helps our meteorology teams more accurately analyze risk posed by trees and how that translates to increased ignition probability. Figure PG&E-9.2.1-2 is an illustration of different scenarios based on IPW risk and FPI values.

FIGURE PG&E-9.2.1-2:
SCENARIOS BASED ON IPW AND FPI VALUES



Catastrophic Fire Behavior

In addition to using historical data and machine learning models to assess the increased probability of utility caused ignitions and wildfire events, we also consider output from millions of fire events simulated by using a state-of-the-art fire simulation technology. This allows us to also evaluate areas where the probability of an outage and ignition event may be low, but the consequences of any ignition could be catastrophic. These locations are only considered for PSPS once the minimum fire potential conditions are met.

By leveraging a large set of fire spread simulations from 2000-2020, published agency literature, workshops with fire scientists, and sensitivity studies, we established our CFB guidance for PSPS decision making starting August 1, 2021. This guidance takes advantage of the fire behavior outputs from fire spread simulations to identify locations where fires are less likely to be contained should a fire ignition occur. The final CFB guidance selected aligns with USFS published research, presented below.

The United States Forest Service Rocky Mountain Research Station, a federal hub of wildfire research, has published documentation relating the observed and modeled fire behavior to the type of fire suppression efforts that may be effective or ineffective. This includes a study of fire line intensity, which analyzes how wildfires can grow and spread. Figure PG&E-9.2.1-3 summarizes the fireline intensity analysis.

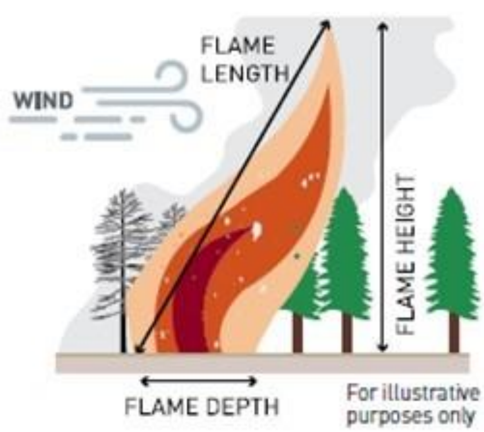
FIGURE PG&E-9.2.1-3:
FIRELINE INTENSITY ANALYSIS

The two rows outlined are considered catastrophic fire behavior, which would necessitate a PSPS.

FLAME LENGTH (L)	FIRELINE INTENSITY	INTERPRETATION
ft	Btu/ft/s	
<4	<100	▪ Fires can generally be attacked at the head by using hand tools ▪ Hand line should hold the fire
4-8	100-500	▪ Fires are too intense for direct attack on the head using hand tools ▪ Hand line cannot be relied on to hold the fire ▪ Equipment such as dozers, pumpers and retardant aircraft can be effective
8-11	500-1,000	▪ Fires may present serious control problems — torching out, crowning and spotting ▪ Control efforts at the fire head will probably be ineffective
>11	>1,000	▪ Crowning spotting and major fire runs are probable ▪ Control efforts at head of fire are ineffective

Fireline intensity is determined by the size and components of flames. It is measured as the rate of heat energy released (British thermal unit (BTU)) per unit length of the fire line (feet) per unit times. It can also be calculated by estimating the flame length, which is the distance measured from the average flame tip to the middle of the base of the fire, as shown in Figure PG&E-9.2.1-4.

FIGURE PG&E-9.2.1-4:
FLAME LENGTH COMPONENTS



PG&E uses flame length and rate of a fires spread from fire simulations in an operational setting to evaluate the potential need to turn off power. As shown in Figure PG&E-9.2.1-4, flame lengths of 8-11 and >11 poses a serious control problem and therefore, are considered CFB and require a PSPS.

Vegetation and Electric Asset Criteria Considerations

We review locations where high-priority trees or electric compliance tags may increase the risk of ignition. We make every effort to address these conditions in advance so that turning off power is only initiated as a last resort.

Priority 1 or Priority 2 Tree Tags

We will turn off power if there are trees with open maintenance tags in areas that also surpass our minimum fire potential conditions. Figure PG&E-9.2.1-5 describes Priority 1 and 2 tree tags. These locations are only considered for PSPS once the minimum fire potential conditions are met.

FIGURE PG&E-9.2.1-5:
PRIORITY 1 AND PRIORITY 2 TREE TAGS

Electric Asset Criteria

PG&E will turn off power if there is equipment with open high-risk safety-related compliance tags. We actively inspect for and schedule work to address these tags. To the extent possible, we fix these issues in the areas that may be within a severe weather footprint before a potential PSPS so we don't have to turn off power. These locations are only considered for PSPS once the minimum fire potential conditions are met.

Transmission PSPS Decision Making

In addition to analyzing distribution circuits, we also review transmission lines and structures in areas experiencing dry, windy weather conditions.

There is no single factor or threshold that will require turning off power for a transmission circuit. When determining whether to turn off power for safety on transmission lines, we review the same minimum fire potential conditions as with distribution lines. If these conditions are met, we will then look to the criteria in

[Figure PG&E-9.2.1-6] below to determine whether a transmission line must be turned off.

FIGURE PG&E-9.2.1-6:
VISUAL REPRESENTATION OF TRANSMISSION SCOPING

We will continue to use findings from Transmission sensitivity studies and incorporate into the PSPS Transmission guidance which is reflected in our Objectives PS-01 and PS-03.

Asset Health

The Operability Assessment (OA) model determines the probability that an asset (a tower or pole structure including the equipment and conductors it supports) will fail during wind gusts of a given speed. While WS is the intensity measure used to determine this probability, the OA considers damage mechanisms, such as corrosion, fatigue, wear, and decay that could lower the capacity of an asset to resist extreme winds.

Vegetation Risk

The Strike Tree model identifies locations where specific trees may be within striking distance of the transmission line. It uses Light Detection and Ranging (LiDAR) information for specific tree attributes and combines that with the FPI to identify sections of lines that have higher risk than others.

Catastrophic Fire Behavior (Consequence)

The CFB is determined using Technosylva's fire spread modeling. Technosylva inputs PG&E weather data, and then runs over 100 million fire spread simulations at 3-hour time intervals for the territory, out multiple days, creating a dataset of potential consequence of new ignitions. To meet CFB guidance, an ignition must meet a set Flame Length, Rate of Spread, and 8 hour burned acreage, in addition to a minimum asset fragility from the OA model. The use of CFB helps PG&E identify areas where the potential consequence from an ignition is high, but where the IPW score may be low due to high circuit resiliency.

Additional Criteria

Vegetation and Asset Hazard Consideration is the last scoping criteria. It is met by the presence of certain transmission asset tags or tree tag designations. Transmission structures that meet minimum Fire Potential Conditions and that also contain trees within striking distance of the line with high priority tags or certain high priority transmission asset tags, and which cannot be mitigated in the time before the weather start, are also recommended for inclusion in PSPS scope.

Public Safety Impact

Low Impact lines are also considered in transmission. The Transmission Asset Health Specialist reviews the system to identify if there are lines that didn't meet any of the above scoping criteria but can be deenergized without incremental impact to customers or other adverse effects to the grid.

9.2.2 Method Used to Compare and Evaluate the Relative Consequences of PSPS and Wildfires

PSPS Risk vs. Benefit Tool

PG&E's PSPS Risk-Benefit Tool addresses the CPUC's requirements that California IOUs quantify the risk and benefits associated with initiating or not initiating a PSPS event for our customers.[179]

We incorporated the risk-benefit analysis into our PSPS execution process to help inform our PSPS decision-making process. The risk-benefit tool aligns with California IOUs and the current Commission-mandated MAVF framework, defined by the S-MAP Settlement Agreement, which specifies how various consequences are factored into a risk calculation.[180] Using this framework, PG&E incorporates event forecast

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179 D.21-06-014, pp. 283-284, Ordering Paragraph 1.

180 D.18-12-014.

information into our PSPS Risk-Benefit Tool which is further described under the Risk Assessment Section below.

After the potential de-energization scope is determined, including the identification of impacted circuits, the scope and the Technosylva wildfire simulation outputs are used as inputs into the Risk-Benefit tool. The Risk-Benefit tool quantifies the potential public safety risk and wildfire risk resulting from the forecasted impacts of the pending weather/PSPS event. The Officer in Charge reviews the output of this analysis to help decide whether to de-energize the areas in consideration to protect public safety.

Risk Assessment

PG&E's PSPS Risk-Benefit Tool uses a California IOU standard MAVF framework that captures the safety, reliability, and financial impacts of identified potential risk events, as outlined in our Enterprise Risk Register.[181] PG&E's MAVF uses a non-linear scaling of consequences reflecting our focus on low-frequency/high-consequence risk events without neglecting high-probability/low-consequence risk events. The PSPS Risk-Benefit Tool outputs MAVF scores which compare the potential de-energization risk from a forecasted PSPS event to the potential risk of catastrophic wildfires if circuits considered for PSPS were to remain energized.

The following inputs are used in calculations to build MAVF risk scores for PSPS events and wildfires, which are weighed against one another.

- Technosylva Wildfire Simulation Data: Fire simulation forecasts on the consequence of a potential wildfire's impact on customers, wildlife, and infrastructure on each circuit for every three hours. These values are based on Technosylva's proprietary and sophisticated wildfire modeling, using real-time weather models, state-of-the-art fuel, and 8-hour fire spread modeling.

- Forecasted Circuits: The final list of the distribution circuits and transmission lines identified as in-scope for a potential PSPS.

- Customer Minutes: Forecasted outage duration that customers will face during the potential PSPS.

- Customers Impacted: Forecasted number of customers to be impacted by the potential PSPS.

- Customer Category and Critical Customer Adjustment Factor: The type of customer (e.g., CC1, MBL, Low-Income, etc.) is incorporated into the analysis using a "critical customer adjustment factor" which is applied to the customer outage duration to reflect a higher risk score for customers who may be more adversely impacted by a potential de-energization event. This scoring adjustment has the potential to change the risk ratio and does not recommend de-energizing a particular circuit during an event. This critical weighting component was included in PG&E's risk scoring to prioritize more vulnerable populations and act as an intermediate solution

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181 Full details of the MAVF methodology are provided in A.20-06-012, PG&E's 2020 RAMP Report, p. 3-3, line 5 to p. 3-15, line 9.

to account for customer resiliency risk that will be further developed jointly with the other IOUs during the S-MAP process.

Once the data is incorporated into the tool, the modeling considerations described below are used to estimate the consequences of the: (1) potential wildfire risk; and (2) PSPS risk at the per-circuit level. A variety of modeling considerations are made using the tool to facilitate calculations, which are included in Table PG&E-9.2.2-1 and summarized in Figure PG&E-9.2.2-1.

TABLE PG&E-9.2.2-1:
PSPS RISK BENEFIT CONSEQUENCE MODELING CONSIDERATIONS

Consequence Type	Wildfire Consequence Considerations	PSPS Consequence Considerations
Safety	Calculated based on maximum population impacts derived from Technosylva wildfire simulation models and a fatality ratio based on National Fire Protection Association data.	Calculated from an estimate of Equivalent Fatalities (EF) per million Customer Minutes Interrupted (MCMI). EF/MCMI ratio is estimated from previous PG&E PSPS and other large external outage events.[(a)]
Reliability	N/A	Calculated directly from the potential number of customers impacted and outage duration based on customer minutes interrupted.
Financial	Calculated based on maximum building impacts derived from Technosylva wildfire simulation models, and a cost per structure destroyed previously evaluated in 2020 RAMP Report.[(b)]	Calculated based on two financial estimates: (1) distribution of a lump sum cost of execution across all relevant circuits, and (2) an estimated proxy cost per customer per PSPS event.[(c)]

(a) Previous PG&E PSPS events include 2019-2021 PSPS events, and other large external outage events include the 2003 Northeast Blackout in New York City, 2011 Southwest Blackout in San Diego, 2012 Derecho Windstorms, 2012 Superstorm Sandy, and 2017 Hurricane Irma, 2021 Texas Blackout event.

(b) PG&E's 2020 RAMP Report, A.20-06-012 (June 30, 2020).

(c) The assumptions used in these calculations, including the proxy cost per customer per PSPS event, will be updated and are not intended to prejudge or create precedent regarding the development of more precise values of resiliency or cost of PSPS metrics being considered in other ongoing proceedings at the CPUC, such as the Risk Based Decision Making Rulemaking, Rulemaking 20-07-013, and the Microgrid and Resiliency Strategies.

Potential Wildfire Risk

Wildfire consequence impacts are calculated based on the outputs from the Technosylva simulations. Variables include: (1) population impacted by wildfire; and (2) structures impacted by wildfire used to calculate natural unit values for two consequence components:

- Wildfire Safety Consequence: EF; and

- Wildfire Financial Consequence: Financial Cost of Wildfire (in dollars).

Potential PSPS Risk

PSPS consequence impacts are based on the following values: duration of de-energization by circuit; and the number of customers impacted by de-energization on each circuit. These input values are used to calculate natural unit values for three consequence components:

- PSPS Safety Consequence: EF as an output of Customer Minutes interrupted;
- PSPS Electric Reliability Consequence: Customer Minutes Interrupted × Critical Customer Adjustment Factor; and
- PSPS Financial Consequence: Financial Cost of PSPS event (in dollars) × Critical Customer Adjustment Factor.

These risk attributes align with how the other IOUs calculate PSPS risk. PG&E continually looks to improve the tool and the accuracy of our PSPS risk calculations. This includes improving our customer risk accounting while ensuring that research into the impact of resiliency is better documented and validated. We are working to improve our consequence estimations by better aligning with our meteorology teams' forecasts and modeling.

After the consequence values (safety, reliability, and financial) are estimated, they are converted into MAVF risk scores. The Risk-Benefit tool then calculates the impacts of a PSPS event and a wildfire, showing if the adverse impact from a PSPS event outweighs the risk of a wildfire. Figure PG&E-9.2.2-1 below depicts the PSPS risk/benefit tool.

**FIGURE PG&E-9.2.2-1:
VISUAL REPRESENTATION OF PSPS RISK BENEFIT TOOL**

9.2.3 Outline of Tactical and Strategic Decision-Making Protocol for Initiating a PSPS/PSPS (Such as Decision Tree)

We know that losing power disrupts lives, especially for our most vulnerable customers. Therefore, we use rigorous, data-driven internal decision-making protocols prior to initiating a PSPS.

PG&E's Internal Decision-Making Process

Officer-in-Charge

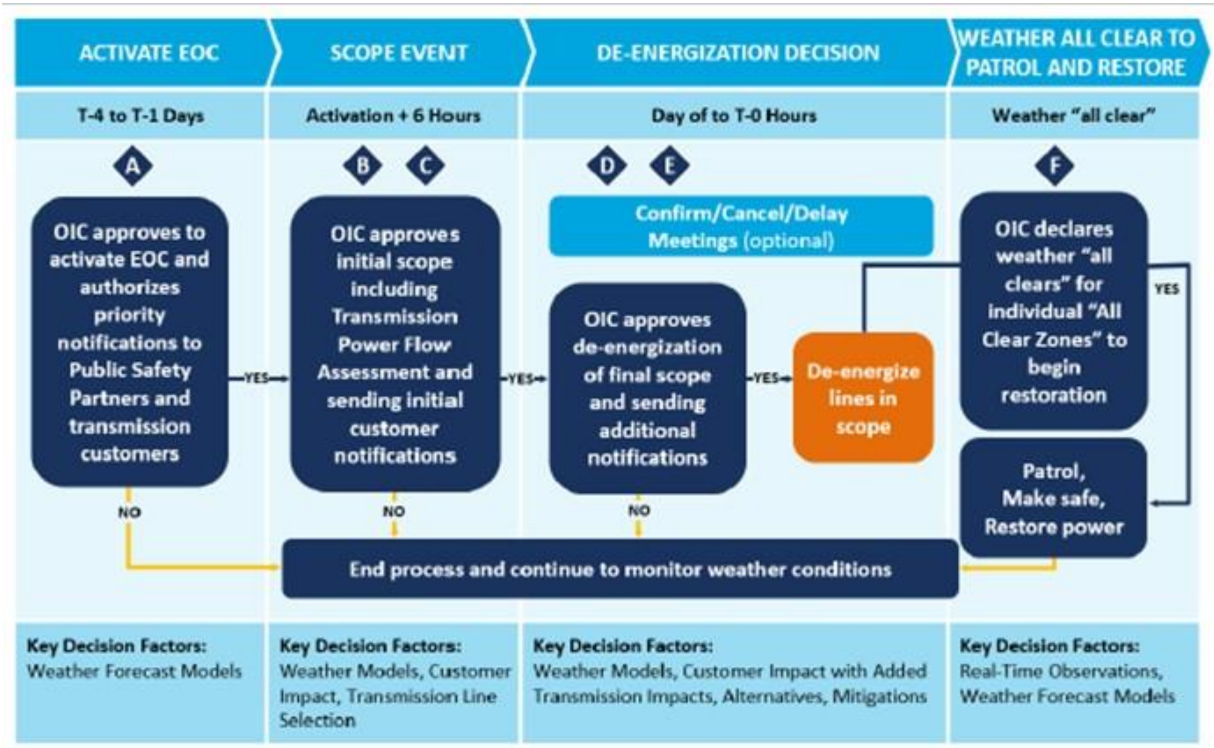
PG&E involves both the Emergency Operations Center (EOC) Commander and our senior management in the decision to initiate PSPS protocols. The Officer-in-Charge (OIC) is a role created for PSPS events to engage senior management in making decisions given the impact of a PSPS event.

During a PSPS event, the OIC is responsible for making the following decisions:

- Activating the PG&E EOC in response to a forecasted PSPS event;
- Approving the list of transmission lines determined to be directly within the scope of the PSPS event;
- Approving initial customer notifications;
- Approving de-energization of distribution and transmission lines within the final event scope (including indirectly affected transmission circuits outside the weather polygon);
- Approving additional customer notifications; and
- Approving weather "all clear" announcements after weather conditions subside and beginning the process of patrols and restoration.

In making these decisions, the OIC receives situational awareness from several PG&E teams including Meteorology, PSPS Technical Engineers, Customer Strategy, the Hazard Awareness Warning Center, and Field Operations. Figure PG&E-9.2.3-1 shows the PSPS decision-making process.

FIGURE PG&E-9.2.3-1:
THE PSPS DECISION MAKING PROCESS



Decision to De-Energize

The OIC will review the information provided by our SMEs and determine when there is an imminent and significant risk of strong winds impacting PG&E assets and a significant risk of large, destructive wildfires should ignition occur. The OIC will determine whether alternatives to de-energization are inadequate to reduce this risk and that the public safety risk of catastrophic wildfire outweighs the adverse impacts of de-energization within the given scope. If the OIC determines that de-energization is necessary to protect public safety, they will approve the decision to de-energize and the final scope of the event and send warning notifications to the customers in scope.

In making this decision, the OIC considers alternatives to de-energization and our ability to mitigate the adverse impacts on customers and communities in areas planned for shutoff. These mitigating steps include warning customers through notifications, mobilizing community assistance locations, implementing sectionalization and microgrids where possible, and providing back up power support under exception circumstances.

If there is a potential transmission PSPS event, we weigh the benefits of de-energizing the transmission lines against the public safety risks. If we determine that the benefits of de-energization outweigh the risks, PG&E will de-energize the identified transmission lines in coordination with the California Independent System Operator, following approval by PG&E's OIC.

Confirm/Cancel/Delay Meetings

After the decision to de-energize is made, PG&E continues to actively monitor weather forecasts up until the planned de-energization time. The EOC Commander, Field Operations, and the Meteorology teams monitor approaching weather, and may hold a series of "Confirm/Cancel/Delay" meetings to:

- Confirm: Confirm that weather has materialized, and de-energization can proceed per plan;
- Cancel: Confirm that the weather threat did not materialize, in all or certain areas, and the de-energization should be cancelled; and
- Delay: Confirm that the weather threat is still imminent but has materialized slower than expected and the final decision to de-energize areas in question needs to be delayed.

This final set of meetings held immediately before the anticipated de-energization allows PG&E to adjust course and reduce or expand the scope, as necessary, if there is an emergent change in the weather.

9.2.4 Protocols for Mitigating the Public Safety Impacts of PSPS, Including Impacts on First Responders, Health Care Facilities, Operators of Telecommunications Infrastructure, and Water Electrical Corporations/Agencies

PG&E mitigates public safety impacts of PSPS through various initiatives such as temporary generation, standing up Community Resource Centers, partnering with CBOs, and sending advanced notifications to Public Safety Partners, critical customers, and others to provide time to prepare for outages.

Temporary Generation

PG&E mitigates potential PSPS customer impact through temporary generation, which can include:

- Distribution Microgrids: Designed to support frequently impacted communities by using temporary generators to power microgrids that safely provide electricity to central corridors (i.e., "Main Street"), critical facilities, and shared community resources.
- Backup Generation: PG&E does not offer backup generation to individual facilities. However, our policy allows certain exceptions for critical facilities when an outage could have a significant impact to public safety or the individual critical customer facility's backup generation and/or emergency plan fails. These exceptions include:
  - High risk to public safety, such as hospitals with active trauma units, critical water or wastewater asset, and city or county EOC;

– High risk of environmental hazard, such as chemical plants which risk toxic spill into local rivers; and

– High risk to essential emergency response and support facilities, such as 911 call centers, water pump availability compromising firefighting, and critical telecommunications equipment or other support businesses that directly affect emergency services provision.

Community Resource Centers

To minimize PSPS outage impacts and serve our communities and vulnerable customers during a PSPS event, PG&E opens Community Resource Centers (CRC) in impacted communities. We describe CRCs in Section 8.4.6.

Community Based Organizations

PG&E partners with CBOs to help mitigate PSPS impacts on customers. These organizations provide a range of support services including assistance with applications for backup portable batteries, emergency preparedness education, accessible transportation resources, hotel stays, and food stipends during a PSPS. More information about how we work with CBOs can be found in Section 8.5.1.1, Section 8.5.2, and Section 8.5.3.

Notifications

Public Safety Partners and Critical Facilities

Throughout PSPS events, PG&E makes special effort to notify Public Safety Partners and critical facilities ahead of PSPS outages. This is to ensure agencies are aware of the potential outage and have sufficient time to prepare and communicate within their community.

During a PSPS outage, Public Safety Partners and critical facilities including transmission-level customers and Publicly Owned Utilities, are notified via:

- Automated notifications via email, text, and telephone. If these customers do not confirm receipt of the automated notification, PG&E representatives from the local EOC, Customer Relationship Managers, or the Critical Infrastructure Lead (CIL) make direct calls to the Public Safety Partners and critical facility contacts to ensure they are aware of the potential PSPS outage;

  – For transmission-level impacts, we attempt to notify within 48-72 hours, depending on scoping; and

  – PG&E's Grid Control Center operators make live calls to transmission-level entities before de-energization and re-energization.

For more information on PG&E's outreach efforts to Public Safety Partners during a PSPS outage, see Section 8.4.3. For more information on PG&E's outreach to critical customers during a PSPS outage, see Section 8.4.4.

Telecommunication Services

PG&E works closely with telecommunication service providers throughout events to coordinate and share information during the weather event. PG&E also provides telecommunications service providers with a dedicated PG&E contact in the EOC known as the CIL, who shares up-to-date event information with them. These partners can reach the CIL 24/7 during an event by e-mail or phone. In addition, PG&E reaches out to telecommunications service providers via email or phone as weather changes or new information regarding the PSPS becomes available.

Transit- or Paratransit-Dependent Persons

PG&E also provides proactive notifications and impacted zip code information to paratransit agencies that serve known transit- or paratransit-dependent persons that may need access to a CRC during an event. All notifications to paratransit agencies include a link to the PSPS emergency website event updates page, and a section called "Additional Resources" with a link to a map showing areas potentially affected by the shutoff.

9.3 Communication Strategy for PSPS

In Section 8.4.4 of the WMP, the electrical corporation must discuss all public communication strategies for wildfires, outages due to wildfires and PSPS, and service restoration. Thus, in this section, the electrical corporation is only required to provide a cross-reference to Section 8.4.4 and any other section of the WMP providing details of the emergency public communication strategy for PSPS implementation.

PG&E is not the lead agency for wildfires and does not communicate to Public Safety Partners regarding the status of wildfires.

For an overview of PG&E's public communication strategies for outages due to wildfires and PSPS, and service restoration, please refer to Section 8.4.3.2, Section 8.4.4, and Section 8.4.4.1.

9.4 Key Personnel, Qualifications, and Training for PSPS

In Section 8.4.2.2 of the WMP the electrical corporation must discuss all key personnel planning, qualifications, and training for wildfires, outages due to wildfires, and PSPS, and service restoration. Thus, in this section, the electrical corporation is only required to provide a cross-reference to Section 8.4.2.2 and any other section of the WMP providing details of key personnel, qualifications, and training for PSPS implementation.

For information regarding PG&E's PSPS key personnel planning, qualifications, and training, please see Section 8.4.2.2.

9.5 Planning and Allocation of Resources for Service Restoration Due to PSPS

In Section 8.4.5.2 of the WMP, the electrical corporation must address planning of appropriate resources (e.g., equipment, specialized workers) and allocation of those resources to assure the safety of the public during service restoration. Thus, in this section, the electrical corporation is only required to provide a cross-reference to Section 8.4.5.2 and any other section of the WMP providing details of resource planning for PSPS implementation.

For information regarding PG&E's planning of appropriate resources and allocations of those resources during PSPS restoration, see Section 8.4.5.2.

PACIFIC GAS AND ELECTRIC COMPANY

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SECTION 10

LESSONS LEARNED

10. Lessons Learned

An electrical corporation must use lessons learned to drive continuous improvement in its WMP. Electrical corporations must include lessons learned due to ongoing monitoring and evaluation initiatives, collaboration with other electrical corporations and industry experts, and feedback from Energy Safety and other regulators.

The electrical corporation must provide a summary of new lessons learned since its most recent WMP submission, and any ongoing improvements to address existing lessons learned. This must include a brief narrative describing the new key lessons learned and a status update on any ongoing improvements due to existing lessons learned. The narrative should be limited to two pages.

The electrical corporation must also provide a summary of how it continuously monitors and evaluates its wildfire mitigation efforts to identify lessons learned. This must include various policies, programs, and procedures for incorporating feedback to make improvements.

Lessons learned can be divided into the three main categories: (1) internal monitoring and evaluation, (2) external collaboration with other electrical corporations, and (3) feedback from Energy Safety or other authoritative bodies. The following are examples of specific potential sources of lessons learned:

- *Internal monitoring and evaluation initiatives:*
  - *Tracking of risk events;*
  - *Findings from root cause analyses and after-action reviews;*
  - *Drills and exercises;*
  - *Feedback from community engagement;*
  - *PSPS events;*
- *Feedback from Energy Safety or other authoritative bodies:*
  - *Areas of continued improvement identified by Energy Safety in the previous WMP evaluation period;*
  - *Findings from wildfire investigations;*
  - *Findings from Energy Safety Compliance Division assessments; and*
- *Collaborations with other electrical corporations.*

In addition to the above potential sources of lessons learned, the electric corporation must detail lessons learned from any and each catastrophic wildfire ignited by its facilities or equipment in the past 20 years, as listed in Section 5.3.2. The electric corporation must also detail specific mitigation measures implemented as a result of these lessons learned and demonstrate how the mitigation measures are being integrated into the electric corporation's wildfire mitigation strategy.

For each lesson learned, the electrical corporation must identify the following in Table 10-1:

- *Year the lesson learned was identified;*
- *Subject of the lesson learned;*
- *Specific type or source of lesson learned (as identified in the bullet lists above);*
- *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(s) the electrical corporation intends to add or modify;*
- *Estimated timeline for implementing the proposed improvement;*
- *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*
  - *If any lessons learned were derived from quantifiable data, visual/graphical representations of these lessons learned in the supporting documentation.*

Our 2023 Wildfire Strategy has been influenced by our response to lessons learned from various sources. A few of the most impactful been:

- <u>Ongoing internal monitoring and evaluations initiatives:</u> 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.
- <u>Feedback from Energy Safety, industry experts, and Stakeholders:</u> 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).
- <u>Collaboration with other electrical corporations:</u> We participate in workshops with other IOUs to address remedies, fuse replacements, covered conductor effectiveness, EPSS settings, and to share other best practices.

Below, we summarize lessons learned since our 2022 WMP and provide an update on ongoing improvements that have been integrated into this WMP. We also provide updates on how we are monitoring and evaluating the lessons learned.

See Table 10-1 below for an overview of lessons learned. To avoid repetition, the lessons learned from catastrophic wildfires ignited by our facilities or equipment listed in

Section 5.3.2 are further discussed in ACI PG&E-22-08. Following Table 10-1 is a brief narrative regarding the lessons learned from catastrophic wildfires.

Ongoing Internal Monitoring and Evaluations Initiatives

PG&E regularly monitors community feedback via Regional Working Groups, Advisory Councils and Wildfire Safety Webinars/Town Halls. Feedback is also received during industry-specific meetings and other community events (see Section 8.4.3.1 and Section 8.5.1.2). Recently, we received feedback that customers need more resources to mitigate outage impacts from our wildfire mitigation programs (PSPS/EPSS). We enhanced customer education about resources for Access and Functional Needs (AFN) customers before, during, and after a wildfire or wildfire safety outage. We are also evaluating expanding programs and eligibility in 2023.

An ongoing improvement has been addressing our inability to provide California Governor's Office of Emergency Services (Cal OES) partners automated customer communications in certain localities where there were 50 or fewer customer impacts. Since 2022, we improved the PSPS communication process with external Office of Emergency Services (OES) partners ensuring they received direct, live calls from their respective Public Safety Specialists in counties with 50 or fewer customer impacts where the customers were to receive automated calls from PG&E. This provided greater situational awareness to the county OES partners and ensured they had visibility into the customer messaging process.

Feedback from Energy Safety, Industry Experts, and Stakeholders

One of the most recent areas of feedback we received from Energy Safety have been areas for continuous improvement, specifically relating to asset inspections. During a 12-week period in 2022, we conducted over 3,000 distribution field QC reviews. While we had set an internal target of 65 percent of reviews achieving a perfect field review, the 3,000-plus field reviews averaged 43.5 percent achieving a perfect review. A separate quality verification of the distribution system inspections found from Week 14 to Week 23, 77.35 percent of the inspections received a pass rate, which was below the internal target pass rate of 90 percent.

During the quality verification process, we found that the most commonly occurring identification failures (which can lead to potential ignitions) relate to improper conductor splices, pole damage, missing/loose/damaged guy wires, exposed/broken/damaged grounds, service connections, missing inspection photos, incorrect tap clamp installations, damaged insulators and king pins, and damaged anchor rods. Starting in 2023, we will transition to 1-3 year inspection cycles for plat maps in HFTD, with frequency assignments based on the Wildfire consequence scores from WDRM v3. (See Section 8.1.3.2.1)

Update Regarding 2021 WMP Remedy 5.4A

In response to 2021 WMP Remedy 5.4.A, discussed in our 2022 WMP, we explained that our Enhanced Ignition Analysis (EIA) Program and supporting asset management teams were primarily focused on equipment failure ignition rates in HFTD to ensure that ignitions in the riskiest geographic regions are prioritized.

In 2022, the EIA Program expanded to include ignition-fault data collection and analysis for most reportable ignition events in HFTD and HFRA, regardless of cause. This has resulted in asset protection corrective actions at the subject circuit level (i.e., modifying protective device settings to better suit conditions at the circuit and help prevent future ignition events) and informed broader wildfire mitigation strategies. We completed 72 fault data reviews in 2022. There was no prior precedent to perform this analysis.

In 2022, PG&E developed procedure documents, implemented field-based mobile applications, and developed process management dashboards to drive adherence to this critical sub-process.

Collaboration With Other Electrical Corporations

Since our 2022 WMP, we have worked with other electric corporations to share best practices. For example, after visits to our Applied Technology Services (ATS) Lab and assessments of our equivalent EPSS programs we learned that San Diego Gas & Electric Company's (SDG&E) findings indicated that including EPSS specific buffer zones in the enablement criteria increased overall safety. We have since updated our EPSS Enablement Criteria based on SDG&E's criteria for Fast Trip activation on Red Flag Warning days only.

In Table 10-1 below we provide an overview of recent lessons learned through internal monitoring and evaluation, external collaboration with other electrical corporations, and feedback from Energy Safety or other authoritative bodies.

TABLE 10-1:
LESSONS LEARNED

ID #	Year of Lesson Learned	Subject	Type or Source of Lesson Learned	Description of Lesson Learned	Proposed WMP Improvement	Timeline for Implementation	Reference
1	2022	Internal monitoring and evaluation initiatives	• Feedback from Community Engagement • Joint IOU AFN Collaborative Planning Team (Federal Emergency Management Agency 6-step Planning Process to develop 2022 AFN Plan) • Joint IOU Statewide AFN Council • Customers participating via Q&A during PG&E Wildfire Safety Webinars/Safety Town Halls)	Customers need more resources to mitigate outage impacts due to wildfire or wildfire safety programs (PSPS/EPSS)	Enhance customer education and awareness of resources for customers with AFN before during and after a wildfire or wildfire safety outage. Evaluate the expansion of programs and eligibility for 2023.	2023	PG&E's 2022 Q1, Q2, and Q3 AFN Plans, dated April 29, 2022, July 29, 2022, and October 31, 2022.[(a)]
2	2022	Internal monitoring and evaluation initiatives	Tracking of Risk Events/ Finding from Fire Root Cause Analysis ignitions within HFTD	Given EPSS implementation, high-impedance fault is one failure mode where EPSS may not prevent the ignition and there is a high probability of ignition. In 2022, out of the 89 CPUC reportable ignitions in HFTD there were 30 reportable EPSS ignitions in HFTD, 16 were characterized by high-impedance faults.	Install system protection equipment with Down Conductor Detection (DCD), where feasible in higher-risk areas.	2023-2024	2023-2025 WMP Section 8.1.2.10; DCD standard has not yet been published.
3	2022	Internal monitoring and evaluation initiatives	Tracking of Risk Events/Finding from Fire Root Cause Analysis	A portion of service-related ignitions in HFTD occurred due to a mechanical force, which resulted in source side wire downs and ignition events. In 2022, out of the 89 CPUC reportable ignitions in HFTD, 15 occurred on a secondary or service facility, and of those, 9 occurred due to a mechanical force.	Require break-away service-connectors in the construction standard for new rebuilds.	2023	2023-2025 WMP, Section 8.1.2.6.2; Break-away standard has not yet been published.
4	2022	Internal monitoring and evaluation initiatives	Tracking of Risk Events/Finding from Fire Root Cause Analysis	PG&E monitored fires outside the service territory and assessed whether PSPS thresholds would have put circuits in the Colorado Fire in Monterey, California and the Coastal Fire in Laguna Niguel, California in scope. This prompted PG&E to look at the thresholds around WS, DFM, and RH that guide EPSS enablement.	Update the EPSS Enablement criteria to be more conservative by adding additional wind and RH criteria and subsequently continuing to reduce to the R2 criteria and the RH/DFM/WS criteria.	Implemented in 2022	Wildfire Risk Governance Committee Decision Outcomes, 3/2/2022 and 6/6/2022[(b)]

TABLE 10-1:
LESSONS LEARNED
(CONTINUED)

ID #	Year of Lesson Learned	Subject	Type or Source of Lesson Learned	Description of Lesson Learned	Proposed WMP Improvement	Timeline for Implementation	Reference
5	2021	Internal monitoring and evaluation initiatives	PSPS events	Cal OES partners were not able to receive automated customer communications in some small localities where there where 50 or fewer customer impacts. OES partners requested that they have visibility into external customer communications related to PSPS messaging during events.	During 2022, the PSPS communication process was improved with external OES partners. This included ensuring county OES partners received direct, live calls from their respective Public Safety Specialists in those counties with 50 or fewer customer impacts, where those customers where to receive automated calls from PG&E. This effort provided greater situational awareness to the county OES partners and ensured they had visibility into the customer messaging process.	Completed in 2022; Ongoing	2022 PSPS Policies and Procedures Guide for Emergency Managers (Section 5)[c]
6	2022	Internal monitoring and evaluation initiatives	PSPS events	During the October 2022 Weather Event, PG&E made every attempt to provide notification of the cancellation of a PSPS event by notifying all affected entities; however, we did not perform these cancellations within the target of two hours of the decision to cancel for portions of the overall 10/22 PSPS event scope. There were limited opportunities to reduce this timeline in event as there were challenges with technology and event complexity, including overlapping notification windows for multiple customer populations.	For future events, PG&E plans to examine areas of improvement to minimize issues arising from overlapping notification windows and improve response time that may be addressed by streamlining processes and making technology upgrades to account for event complexity.	Planned for 2023	PG&E PSPS Report to the CPUC, October 22-24, 2022 Weather Event, dated November 7, 2022[d]

**TABLE 10-1:
LESSONS LEARNED
(CONTINUED)**

ID #	Year of Lesson Learned	Subject	Type or Source of Lesson Learned	Description of Lesson Learned	Proposed WMP Improvement	Timeline for Implementation	Reference
7	2021	Feedback from Energy Safety or other authoritative bodies	Areas of Continuous Improvement – Operations	After EPSS was initiated, CPUC reportable ignitions were reduced by about 80 percent on EPSS enabled circuits compared to the prior 3-year average. However, the averted ignitions have impacted customers' electric reliability. PG&E recognizes that it could have done a better job of communicating these changes to customers before they were implemented. After implementing the EPSS program, PG&E held more than a dozen informational webinars for communities experiencing these outages and heard first-hand from customers who had experienced hardships from EPSS.	PG&E has expanded the EPSS mitigation across all HFRA and EPSS buffer area distribution circuits, while minimizing and mitigating power loss impacts on customers by applying learnings from 2021 and optimizing device settings at the outset including adjusting settings in a more coordinated and individualized manner to reduce outages, using helicopters to more rapidly check lines that have tripped, installing animal protection on equipment, and targeted asset hardening.	Implemented in 2022; Ongoing	Response to Request for a Final Report, Case No. 14-CR-00175-WHA, Document 1519, dated November 17, 2021 (discussing the EPSS program).(e)
8	2021	Feedback from Energy Safety or other authoritative bodies	Areas of Continuous Improvement – Modeling Prioritization & Verifiable Records/Data Improvement	Based on recommendations from the continual examination of all aspects of the PSPS Program, including the performances of its models, power-restoration teams and customer notification processes, PG&E's PSPS models incorporated Tree Overstrike as an independent trigger for de-energization. The machine-based learning assessment indicated that PG&E should integrate a given grid cell's Tree Overstrike into the broader calculation of the probability of an outage and associated potential ignition.	For 2021, PG&E's models were improved to consider the relative amount of Tree Overstrike (the approximate linear distance of trees that are tall enough to fall on PG&E lines, as estimated based on aerial LiDAR scans) as well as outstanding high-priority vegetation and asset maintenance tags. PG&E expects that each year we will evaluate potential changes to our program to make the program's targeting of wildfire risk more effective. This includes altering the models' parameters, incorporating additional data or making other changes. Any such changes would be subject to a robust weather-backcasting analysis to confirm that the models would have effectively prevented catastrophic wildfires.	Continuous	Response to Request for a Final Report, Case No. 14-CR-00175-WHA, Document 1519, dated November 17, 2021 (discussing tree overstrike and PSPS protocols).(f)

TABLE 10-1:
LESSONS LEARNED
(CONTINUED)

ID #	Year of Lesson Learned	Subject	Type or Source of Lesson Learned	Description of Lesson Learned	Proposed WMP Improvement	Timeline for Implementation	Reference
9	2020	Feedback from Energy Safety or other authoritative bodies	Areas of Continuous Improvement – Inspections	In response to a condition of probation agreed upon by PG&E and the Federal Monitor, PG&E stood up our Vegetation Management Inspector (VMI) program, now known as Construction Management. The organization includes PG&E-employed supervisors and management and 95 Senior VMI, formerly known as VMIs, including 30 employed by PG&E. A routine VM program inspecting overhead electric distribution facilities at least annually will help identify and clear vegetation that might grow or fall into utility equipment.	PG&E is moving towards a 100% work verification model in our routine VM program in HFTDs. In 2021, PG&E tripled our work verification workforce by adding 200 additional inspectors to perform this work. PG&E deployed, where feasible, the use of vehicle-based LiDAR technology as a further check on the quality of its VM patrols in HFTDs. Vehicle-based LiDAR scans following a routine inspection and its associated tree are meant to help objectively confirm that the required clearance around the conductors has been achieved.	Ongoing	Response to Request for a Final Report, Case No. 14-CR-00175-WHA, Document 1519, dated November 17, 2021 (discussing Vegetation Management Improvements)[g]
10	2021	Feedback from Energy Safety or other authoritative bodies	Areas of Continuous Improvement – Training	Experiential field training should be incorporated into the curriculum and further use testing both during and at the end of asset inspection trainings to ensure comprehension and retention of information.	PG&E updated our training content based on feedback and learnings from 2021 and is developing additional knowledge assessments and testing that we plan to incorporate in our training programs in 2022.	Completed in 2022	Response to Request for Critiques, Case 14-CR-00175-WHA, Document 1538, dated December 16, 2021 (discussing Electric Infrastructure Inspections and Remediation Work).[h]

TABLE 10-1:
LESSONS LEARNED
(CONTINUED)

ID #	Year of Lesson Learned	Subject	Type or Source of Lesson Learned	Description of Lesson Learned	Proposed WMP Improvement	Timeline for Implementation	Reference
11	2022	Feedback from Energy Safety or other authoritative bodies	Areas of Continuous Improvement – Inspections	During a 12-week period in 2022, PG&E conducted over 3,000 distribution field QC reviews. While PG&E had set an internal target of 65 percent of reviews achieving a perfect field review, the 3,000-plus field reviews averaged 43.5 percent achieving a perfect review. A separate quality verification of the distribution system inspections found that over a period from Week 14 to Week 23, 77.35 percent of the inspections received a pass rate, which was below the internal target pass rate of 90 percent. The most commonly occurring identification failures (many of which can lead to potential ignitions and wildfires) noted in the quality verification process relate to improper conductor splices, pole damage, missing/loose/damaged guy wires, exposed/broken/damaged grounds, service connections, missing inspection photos, incorrect tap clamp installations, damaged insulators and king pins, and damaged anchor rods.	Starting in 2023, we will transition to 1-3 year inspection cycles for plat maps in HFTD, with frequency assignments based on the Wildfire consequence scores from WDRM v3.	Planned for 2023	PG&E Independent Safety Monitor Status Report, dated October 4, 2022.(i)
12	2022	Collaborations with other electrical corporations	Sharing of best practices	Based on assessments of equivalent EPSS programs among the IOUs and sharing of information inclusive of site visits at PG&E's ATS lab, PG&E learned that SDG&E's findings indicated that including EPSS specific buffer zones in the enablement criteria increased overall safety.	PG&E updated EPSS Enablement Criteria to include EPSS specific buffer zones based on SDG&E's criteria for Fast Trip activation on Red Flag Warning days only.	Implemented in 2022	PG&E's 2022 Wildfire Mitigation Plan Response to Revision Notice (RN-PG&E-22-12), dated July 11, 2022, including "Utility Benchmarking of Fast Trip Schemes and Relay Technologies for Fire Mitigation" and "Fast Trip Setting California IOU Comparison" dated June 2022.(j)

TABLE 10-1:
LESSONS LEARNED
(CONTINUED)

ID #	Year of Lesson Learned	Subject	Type or Source of Lesson Learned	Description of Lesson Learned	Proposed WMP Improvement	Timeline for Implementation	Reference
13	2022	Collaborations with other electrical corporations	Sharing of best practices	In response to Revision Notice 22-09, PG&E collaborated with Southern California Edison Company and SDG&E to develop regional AOCs for focused tree removal based on SDG&E's AOC program.	Analyze 47 counties in PG&E service territory to improve understanding and document regional vegetation and ignition/outage risk. Develop a pilot program for focused tree inspections and mitigation in high risk AOCs.	AOCs were identified in 2022. The focused tree inspection pilot program will begin in 2023.	PG&E's 2022 Revised WMP response to Revision Notice 22-09, pp. 743-752.[k]

(a) PG&E's AFN Plan for PSPS Support Quarterly Progress Reports in R.18-12-005. Specifically, Quarterly Report for Jan. 1, 2022 to Mar. 31, 2022 (Apr. 29, 2022); Quarterly Report for Apr. 1, 2021 to Jun. 30, 2021 (Jul. 30, 2021), and Quarterly Report (Jul. 1, 2022 to Sept. 30, 2022) (Oct. 31, 2022).

(b) See relevant portions of PG&E's Wildfire Risk Governance Committee Presentations (3/2/2022 and 6/6/2022) in Attachments 2023-03-27_PGE_2023_WMP _R0_Section 10_Atch01 and 2023-03-27_PGE_2023_WMP _R0_Section 10_Atch02.

(c) PG&E Public Safety Power Shutoff Policies and Procedures, Emergency Managers (July 2022). See Appendix E.

(d) PG&E PSPS Report to the CPUC, October 22 24, 2022 Weather Event (Nov. 7, 2022). See Appendix E.

(e) *United States v. Pacific Gas and Electric Company*, Case No. 14-CR-00175-WHA, Response to Request for a Final Report (Nov. 17, 2021), pp. 9-11. Available at https://docs.publicnow.com/viewDoc?hash_primary=B618903F0CA43A4F6033CFBFAA73D28CA2088D92.

(f) Id. at pp. 11-16.

(g) Id. at pp. 18-26.

(h) *United States v. Pacific Gas and Electric Company*, Case No. 14-CR-00175-WHA, Response to Request for Critique (Dec. 16, 2021), pp. 10-13. Available at https://s1.q4cdn.com/880135780/files/doc_downloads/wildfire_updates/2021/12/PG-E-Response-to-Federal-Monitor-Final-Report-December-16-2021.pdf.

(i) Filsinger Energy Partners, PG&E Independent Safety Monitor Status Update Report (October 4, 2022), p. 18. See Appendix E.

(j) PG&E's 2022 Wildfire Mitigation Plan Response to Revision Notice (RN-PG&E-22-12) (July 11, 2022), pp. 62-85; *Utility Benchmarking of Fast Trip Schemes and Relay Technologies for Fire Mitigation*; *Fast Trip Setting California IOU Comparison* (June 2022).

(k) PG&E's 2022 Wildfire Mitigation Plan Update – Revised, OEIS Docket #2022-WMP (July 26, 2022), pp. 743-752.

Catastrophic Fires From the Past 20 Years

In compliance with D.14-02-015, PG&E began tracking wildfires potentially associated with our electric facilities in 2014. Table 5-4 in Section 5.3.2 provides additional details about these incidents. As discussed, the information provided in Table 5-4 is based on information available to PG&E at the time of the 2023 WMP filing. PG&E requested data from CAL FIRE in December 2022 for fires occurring between 2002 and 2014 in an attempt to provide additional information responsive to the Guidelines. The information provided by CAL FIRE in mid-January did not provide sufficient information to meaningfully respond further to Energy Safety's request in the Guidelines.

PG&E has a separate ACI related to lessons learned from catastrophic wildfires (ACI PG&E-22-08). In response to that ACI, we provide the lessons learned from the electrical corporation ignited catastrophic fires from 2014 to the present contemplated in this section. To avoid redundancy, please refer to that ACI response for the information and documentation requested in this section.

In addition to specific lessons learned from individual fires, we ultimately monitor our wildfire mitigation efforts through Wildfire Risk Weekly Operating Reviews which cover the following topics: ignitions; implementation of EPSS and other operational mitigations; and progress on the WMP. The weekly discussion is facilitated by the Community Wildfire Safety Program Project Management Office and attendees include PG&E's Chief Executive Officer and Executive Officer Team. We use these weekly meetings to learn about our mitigation efforts and make necessary adjustments in real time.

PACIFIC GAS AND ELECTRIC COMPANY

2023-2025 WILDFIRE MITIGATION PLAN

SECTION 11

CORRECTIVE ACTION PROGRAM

11. Corrective Action Program

In this section, the electrical corporation must describe its corrective action program. The electrical corporation must present a summary description of the relevant portions of its existing procedures.

The electrical corporation must report on how it maintains a corrective action program (CAP) to track formal actions and activities undertaken to:

- *Prevent recurrence of risk events;*
- *Address findings from wildfire investigations (both internal and external);*
- *Address findings from Energy Safety's Compliance Assurance Division (i.e., audits and notices of defect and violation); and*
- *Address areas for continued improvement (ACI) identified by Energy Safety as part of the Wildfire Mitigation Plan (WMP) evaluation.*

The electrical corporation must report on how it reviews each improvement area in accordance with its corrective action program. At a minimum, the electrical corporation must:

- *Identify Insufficient Occurrence And Response: Identify targeted corrective actions for areas where the event occurrence, response, or feature was insufficient;*
- *Identify Actions To Reduce Recurrence: Identify improvement actions (as applicable) to reduce the likelihood of recurrence, improve response/mitigation actions, or improve operational procedures or practices;*
- *Track Implementation: Track the improvement action plan and schedule in the electrical corporation's action tracking system;*
- *Improve External Communication**:** For areas where weaknesses were identified in the response of external agencies, develop a communication plan to share the information and conclusion with the responsible agency. The completion of this action and the agency's response must be documented;*
- *Integrate Lessons Learned From Across The Industry**:** Identify applicable generic lessons learned to improve the overall effectiveness of the electrical corporation WMPs; and*
- *Share Lessons Learned With Others**:** Identify and communicate any significant generic lessons learned that should be disseminated broadly (i.e., to other electrical corporations and responsible regulatory authorities, such as Energy Safety or California Department of Forestry and Fire Protection (CAL FIRE)).*

The WMP should not include detailed corrective action plans for each risk event, finding, and/or improvement area. However, this documentation must be made available to Energy Safety upon request.

Introduction

In the sections below, PG&E first reports on how we maintain a corrective action program (CAP) to track formal actions and activities. Next, we discuss how we review each improvement area in accordance with our CAP.

Maintaining a CAP to Track Formal Actions and Activities

Through our CAP, Pacific Gas and Electric Company (PG&E) identifies, evaluates, resolves, and tracks actual or potential issues, problems, failures, nonconformities, concerns, and opportunities for improvement (collectively, called CAP issues) based on probability of occurrence.[182] CAP is a risk-informed, risk-driven process by which the organization learns from equipment, programmatic, organizational, and human performance issues.

CAP is a commitment database and tracking tool we rely on to ensure we have knowledge of, and visibility into, CAP issues and the means to track progress as we resolve them. CAP is an enterprise-wide tool used to track and manage a wide variety of issues and is not limited to risk events, wildfire investigations, or findings from regulatory agencies.

The CAP program is not specifically designed to improve external communications, integrate lessons learned from across the industry, or share lessons learned with others. There may be CAP issues whose resolution includes improving external communications, integrating lessons learned from industry or sharing lessons learned with others, but these items are not generally addressed as part of the CAP process.

For example, when Energy Safety issues PG&E a Notice of Violation (NOV) or Notice of Defect (NOD), PG&E manages it to completion through the CAP process. PG&E's responses are typically publicly available through the Energy Safety website.

PG&E maintains a CAP to track formal actions and activities undertaken to:

- Prevent recurrence of risk events;
- Address findings from wildfire investigations (both internal and external);
- Address findings from Energy Safety's Compliance Assurance Division (i.e., audits and notices of defect and violation); and
- Address ACIs identified by Energy Safety as part of the WMP evaluation.

Prevent Recurrence of Risk Events

182 As described in the PG&E Enterprise CAP Procedure (GOV-6101P-08) Revision 2 in Appendix E.

The goal of PG&E's CAP is to minimize the recurrence of risk events. The process the Corrective Action Review team (the review team) follows includes assigning a CAP risk level for issues that are entered into the CAP database. The review team recommends an evaluation type based on the level of potential safety, reliability, financial, compliance, environmental, and/or reputational risk.

CAP evaluations include Root Cause Evaluations (RCE), Apparent Cause Evaluations (ACE), Common Cause Evaluations (CCE), and Work Group Evaluations (WGE).[183]

- The RCE process is a formal and rigorous investigation that uses industry-accepted analysis methods to identify the root cause of the problem and identifies corrective actions that prevent or reduce the likelihood of a recurrence for the same or similar root cause;
- An ACE is a formal investigation based on readily available data and information which uses industry-accepted analysis methods to provide reasonable assurance that the cause of the problem was identified while also determining corrective actions to reduce the likelihood or repeat of a similar occurrence;
- CCE are analyses used to identify common underlying elements between different, unique, but similar events or issues. These elements may be anything from a common failure mode to a common cause that may or may not require further investigation; and
- WGE are the lowest level of evaluation and can be used to analyze issues, ideas, and potential opportunities for improvement.

A corrective action is developed for each issue and assigned to action owners who monitor actions to ensure they are completed by the agreed upon due date and verifies each action is completed.

To prevent recurrence of CAP issues, teams define corrective actions such as developing new training programs or revising standards or procedures focused on preventing recurrence of the specific issue. The CAP team and SMEs work together to develop and implement the agreed upon solutions and track progress through the CAP database from evaluation through implementation. The CAP team reviews and tracks open issues daily until the corrective actions are implanted and the CAP can be marked complete and closed-out.

Address Findings from Wildfire Investigations (Both Internal and External)

Our CAP addresses findings from internal and external wildfire investigations by tracking and reporting on investigations conducted by the Electrical Incident Investigation (EII) group. The EII group is responsible for investigating California Public Utilities Commission (CPUC) reportable events, Electric Incident Reports (EIR), and

[183] As described in Procedure GOV-6102P-06 – Link to full document in Appendix E.

non-CPUC reportable events. A wildfire CAP is submitted when the EIR criteria are met.[184]

The EII group identifies insufficient occurrence and response by investigating the following:

- How assets in the field performed in each incident;
- An apparent cause of each incident;
- A probable cause of each incident;
- A contributing cause to each incident;
- An engineering or design issue which, if changed, may reduce the probability of the incident recurring;
- A change to work procedure or process which, if changed, may reduce the probability of the incident recurring;
- Corrective actions that PG&E can take in managing our assets or our work processes to improve the safety of employees and the public, and to improve asset performance; and
- A failure to meet PG&E or CPUC asset work-process standards that could lead to a CPUC self-report.

We create a CPUC 20-day report to provide a status of the investigation within 20 business days of reporting the incident. A CAP is created when it is likely that the incident occurred because PG&E equipment, processes, procedures, and/or standards did not meet PG&E or CPUC standards.

When the investigation report is complete, any causal evaluations, EIRs, or documentation about the completed investigation are uploaded to the CAP database and an email is sent to key internal stakeholders. EIRs are made available to the public on PG&E's investor relations webpage. Causal Evaluations and EIRs are provided to governing agencies upon request. If any new corrective issues are identified during the investigation, then a new CAP is created.

CAPs are tracked to completion by issue owners and evaluated for quality closure[185] by the CAP group. The CAP is managed in SAP and allows tracking of overall issues and action items taken to resolve the issue. A target due date is set when an issue is accepted and changes to due dates are tracked and approved as per our operating

184 As described in the Electric Incident Reporting On-Call Representative Procedure (RISK-6305P-01), Rev. 09 (Mar. 17, 2022). See Appendix E.

185 Per the guidance in the PG&E Enterprise CAP Procedure (GOV-6101P-08), Rev. 2 (Jan. 14, 2022), pp. 27-28. See Appendix E.

procedure. We use dashboards to prioritize work by risk level and to track overdue and coming due CAPs.

We continue to improve how we communicate our findings from wildfire investigations to external agencies. For example:

- ACI PG&E-22-08 analyzes how lessons learned from past catastrophic fires are tied to the causes of past PG&E-equipment related catastrophic fires beyond what was provided in the 2022 WMP in RN-PG&E-22-01; and

- The Envista Root Cause Analyses (RCA) Report[186] provides RCAs of the 2017-18 wildfires found to have been caused by PG&E. The report also includes a corrective action report.

Since 2020, PG&E's Electric Investigation teams have been meeting quarterly with the other Investor-Owned Utilities (IOU) to share lessons learned from incidents in which a self-report was created. Additional meetings with IOUs helped decide how to interpret requirements set forth in Energy Safety's emergency rulemaking for 29300 A(1), A(2) and B.[187] The meetings have allowed us to understand what each utility currently investigates.

Additionally, PG&E's Ignition Investigation team reviews and categorizes all ignition events that meet the criteria identified in Fire Incident Data Plan and Reporting Procedure (RISK-6306P-01). This procedure describes the process for complying with CPUC Decision 14-02-015[188] which requires us to report annually all fire ignitions associated with our electric facilities that meet the criteria specified in the decision. The purpose of the procedure is to identify and understand PG&E facility ignition characteristics, to assess ignition trends, and to formulate ignition prevention strategies. We use this data to analyze risk based on historic ignition frequency and to inform asset strategy.

Address Findings from Energy Safety's Compliance Assurance Division (i.e., Audits and Notices of Defect and Violation)

Energy Safety conducts inspections, audits, and investigations to oversee utility compliance with approved WMPs. We are required to correct violations and defects identified by Energy Safety per Energy Safety's Compliance Process. PG&E's CAP thoroughly reviews and addresses findings related to Energy Safety Compliance Assessments, notably NOVs and NODs.

An NOV letter lists the non-compliance with the WMP or any law, regulation, or guideline within Energy Safety's authority. An NOD letter identifies instances of deficiencies, errors, or field conditions that increase the risk of ignition posed by electrical lines and equipment and that require corrective action. Each NOV or NOD

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186 Envista Forensics, Root Cause Analyses 2017-2018 Wildfires, (July 6, 2022). See Appendix E.

187 14 CFR § 29300. See Appendix E.

188 D.14-02-015. See Appendix E.

includes a deadline for us to provide a formal response about how we plan to remedy the violation or defect and prevent recurrence. Each violation or defect is assigned a risk category (severe, moderate, minor) and a required correction timeline.

When a NOV or NOD is received, we develop a response based on the following process:

- Create a CAP to track the NOV/NOD and associated corrective actions;
- Notify key internal stakeholders;
- Hold a stakeholder engagement call to review the NOV and NOD in detail and discuss corrective actions;
- Draft the NOV/NOD response and obtain senior leadership approval;
- Submit the NOV/NOD response to Energy Safety;
- Notify internal stakeholders about our final NOV/NOD response;
- Update the CAP to track any corrective actions; and
- Close the CAP once all corrective actions are completed.

Address ACIs Identified by Energy Safety as Part of the WMP Evaluation

Since the filing of original WMP in 2019, the Wildfire Safety Division, now known as Energy Safety, has reviewed wildfire mitigation plans to evaluate areas where the utilities could improve their wildfire initiatives. We have received remedies and ACIs to be addressed as part of a revision notice or a requirement for future WMPs. We have responded to each of those remedies and ACIs through corrective actions and will continue to do so.[189]

As part of the approval of the 2022 WMP, Energy Safety identified 35 ACIs for PG&E. The CWSP PMO monitors each ACI topic and provides corrective actions to Energy Safety. The ACIs stemming from the 2022 Revised WMP and our responses to them are included in Appendix D.

In the 2023 WMP, we have evaluated whether any remedies or ACIs that are ongoing are appropriate topics for objectives and targets for quarterly and annual reporting purposes. Prior corrective actions also help us plan and execute subsequent WMPs. The issues raised by Energy Safety and other stakeholders have improved our WMPs over time.

We note that some of the ACIs from the 2022 WMP are directed to multiple utilities. In those instances, we are working closely with other utilities to address the areas for

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189 For example, see PG&E's Revised 2022 Wildfire Mitigation Plan, OEIS #2022-WMP (July 26, 2022).

improvement. Lessons learned from these shared ACIs will then take place across the industry.

Reviewing Improvement Areas in Accordance with the Corrective Action Program

Identify Insufficient Occurrence and Response

Through our CAP, we identify corrective actions such as developing new training programs or revising standards or procedures focused on preventing recurrence of issues, problems, failures, nonconformities, or other concerns. As described in this Section above, these corrective actions may be identified through various evaluations and analyses. More specifically, RCE and ACE are formal investigations that help us identify insufficient occurrences or responses. In addition, our EII Group investigates apparent, probable, and contributing causes to CPUC reportable events. The group submits a wildfire CAP when EIR criteria are met.

After a CAP is submitted, SMEs work together to develop and implement the agreed upon solutions and track progress through the CAP database from evaluation through implementation. Each CAP issue is assigned to an action owner who monitors actions to ensure they are completed by the agreed upon due date and verifies each action is completed.

Identify Actions to Reduce Recurrence

The goal of PG&E's CAP is to minimize the recurrence of risk events. To reduce the recurrence of risk events, the Corrective Action Review team recommends an evaluation type based on the level of potential safety, reliability, financial, compliance, environmental, and/or reputational risk. A corrective action (e.g., developing new training programs or revising standards or procedures) is developed for each issue and assigned to action owners who monitor actions to ensure they are completed.

For additional details, please the portion of this Section titled Prevent Recurrence of Risk Events above. It includes a discussion on the four types of evaluations and analysis performed by PG&E as part of the CAP process to not only understand root cause but to prevent recurrence in the future.

Track Implementation

CAPs are tracked to completion by issues owners and evaluated for closure by the CAP group. The CAP is managed in SAP and allows tracking of overall issues and action items taken to resolve the issue. A target due date is set when an issue is accepted and changes to due dates are tracked and approved as per our operating procedure. We use dashboards to prioritize work by risk level and to track overdue and coming due CAPs.

For additional information, please see the CAP Procedure cited earlier in this Section (GOV-6101P-08). The Standard includes information regarding the quality closure criteria for CAP issues, including actions take to address CAP issues, in Appendix C. Appendix D to the Standard also contains Closure Documentation Guidance for Corrective Actions, including recommended documentation for completed actions.

Improve External Communication

As described above, our CAP addresses findings from internal and external wildfire investigations by tracking and reporting on investigations conducted by our EII group. The EII group is responsible for investigating CPUC reportable events, EIR, and non-CPUC reportable events. As indicated above, a wildfire CAP is submitted when the EIR criteria are met.

We create a CPUC 20-day report to provide a status of the investigation within 20 business days of reporting the incident. A CAP is created when it is likely that the incident occurred because PG&E equipment, processes, procedures, and/or standards did not meet PG&E or CPUC standards.

When the investigation report is complete, any causal evaluations, EIRs, or documentation about the completed investigation are uploaded to the CAP database and an email is sent to key internal stakeholders. EIRs are made available to the public on PG&E's investor relations webpage. Causal Evaluations and EIRs are provided to governing agencies upon request. If any new corrective issues are identified during the investigation, then a new CAP is created.

PG&E's CAP also thoroughly reviews and addresses findings related to Energy Safety Compliance Assessments, notably NOVs and NODs. An NOV letter lists the noncompliance with the WMP or any law, regulation, or guideline within Energy Safety's authority. An NOD letter identifies instances of deficiencies, errors, or field conditions that increase the risk of ignition posed by electrical lines and equipment and that require corrective action. Each NOV or NOD includes a deadline for us to provide a formal response about how we plan to remedy the violation or defect and prevent recurrence. When our response to the NOV or NOD is complete, we submit it to Energy Safety. In addition to the CAP process, we meet with Energy Safety every two weeks to discuss any potential NOVs or NODs found during field inspection activities.

We also are continuing to improve how we communicate our findings from wildfire investigations to external agencies as demonstrated in response to ACI-PG&E-22-08.

Integrate Lessons Learned From Across The Industry

PG&E discusses lessons learned based on feedback from Energy Safety, industry experts, and stakeholders and through collaboration with other electric corporations in detail in Section 10 of this WMP. Table 10-1 includes an overview of these lessons learned by subject. Lessons learned relate to the following topics: customer resources due to wildfire or wildfire safety programs; EPSS implementation; source side wire down and ignition events; PSPS thresholds; customer communications related to PSPS events; vegetation management inspections and removal; field training; and more.

Some of the ACIs from the 2022 WMP were directed to multiple utilities. In those instances, we are working closely with other utilities to address the areas for improvement. Lessons learned from these shared ACIs will then take place across the industry and the utilities continue to meet and discuss their findings.

PG&E is also grateful for the guidance and feedback from Energy Safety throughout the WMP process and is continually working to incorporate that feedback into each successive WMP.

Share Lessons Learned With Others

As stated above, PG&E meets regularly with other electric corporations and responsible regulatory authorities to share lessons learned and other relevant information. Some of these meetings include Energy Safety led workshops while others are self-directed. Throughout this WMP, we have identified instances of this type of collaboration as referenced, in part, below.

- In Section 5.4.5, we describe how we collaborated with responsible regulatory authorities to address environmental compliance and permitting challenges;
- In Sections 8.4.3 and 8.4.4, we discuss our external collaboration and coordination relating to emergency planning and communication;
- In Section 10, Table 10-1, we describe lessons learned from various sources including ongoing internal monitoring, and evaluations initiatives, feedback from Energy Safety, industry experts, and stakeholders, and collaboration with other electrical corporations;
- In Appendix D, ACI-PG&E-22-02 we describe several activities that we are participating in with other electric corporations and industry groups to address climate change risk;
- In Appendix D, ACI-PG&E-22-11, we discuss our work with other utilities to evaluate lessons learned relating to the effectiveness of covered conductor;
- In Appendix F, Table 8-61 we list the hundreds of meetings and presentations we have participated in with counties, cities, tribal agencies, fire protection districts, and other organizations to discuss topics related to what we have learned about wildfire safety and wildfire preparations.

PG&E looks forward to continuing to share lessons learned in future WMPs or in other venues as we work together to eradicate catastrophic wildfires.

PACIFIC GAS AND ELECTRIC COMPANY

2023-2025 WILDFIRE MITIGATION PLAN

SECTION 12

NOTICES OF VIOLATION AND DEFECT

12. Notices of Violation and Defect

Within an NOV or NOD, Energy Safety directs an electrical corporation to correct a violation or defect within a specific timeline, depending on the risk category of the violation or defect. The electrical corporation has 30 days to respond to the NOV or NOD and provide a plan for corrective action. Following completion of the corrective action, the electrical corporation must provide Energy Safety with documentation validating the resolution or correction of the identified violation or defect. Energy Safety includes the electrical corporation's response and the resolution status of any violations or defects in the summaries it provides to the CPUC.

In Table 12-1 of the WMP, the electrical corporation must provide a list of all open violations and defects as of January 1, 2023.

Table 12-1 below lists PG&E's one open Notice of Defect as of January 1, 2023. We did not have any open Notices of Violation as of January 1, 2023.

TABLE 12-1:
LIST OF OPEN COMPLIANCE VIOLATIONS AND DEFECTS

ID	Type	Severity	Date of Notice	Date of Response	Summary Description of Violation/Defect	Estimated Completion Date	Summary Description of Correction
NOD_MJ4_PGE _20211207-01	Defect	Minor	3/11/2022	4/25/2022	Energy Safety found that a structure had “excessive splicing in a single span.” Energy Safety notes that multiple splices on a single phase of a span indicate that the conductor has required repair multiple times and therefore, a span with an excessive number of splices is an indicator of increased risk of conductor failure and ignition.	Pending with Energy Safety	We did not agree with Energy Safety that this was a defect that warranted a prioritized replacement of the span under the minor risk categorization timeline.[a] We communicated these details to Energy Safety on April 25, 2022. We look forward to resolving this issue with Energy Safety.

(a) We inspected the span on April 20, 2022 and found no immediate safety concerns. More specifically, the visual and infrared inspections, and the IR imaging did not identify any immediate safety concerns. The crossarms and supporting structures were in serviceable condition. Finally, the location at issue is in the bottom 50 percent of PG&E’s wildfire risk per the WDRM. We also provided details around internal guidance for managing splices and mitigating any risk associated with using them.

PACIFIC GAS AND ELECTRIC COMPANY

2023-2025 WILDFIRE MITIGATION PLAN

APPENDIX A

DEFINITIONS

Appendix A – Definitions

Appendix A.1 – Energy Safety Definition of Terms

Unless otherwise expressly stated, the following words and terms, for the purposes of these Guidelines, have the meanings shown in this chapter.

Terms Defined in Other Codes

Where terms are not defined in these Guidelines and are defined in the Government Code, Public Utilities Code (Pub. Util. Code), or California Public Resources Code (PRC), such terms have the meanings ascribed to them in those codes.

Terms Not Defined

Where terms are not defined through the methods authorized by this section, such terms have ordinarily accepted meanings such as the context implies.

Definition of Terms

TABLE PG&E-A-1:
DEFINITION OF TERMS – ALPHABETICAL BY TERM

Term	Definition
Access and Functional Needs population (AFN)	Individuals, including, but not limited to, those who have developmental or intellectual disabilities, physical disabilities, chronic conditions, or injuries; who have limited English proficiency or are non-English speaking; who are older adults, children, or people living in institutionalized settings; or who are low income, homeless, or transportation disadvantaged, including, but not limited to, those who are dependent on public transit or are pregnant. (California Government Code 8593.3(f)(1)).
Asset (utility)	Electric lines, equipment, or supporting hardware.
At-risk species	See “high-risk species.”
Benchmarking	A comparison between one electrical corporation’s protocols, technologies used, or mitigations implemented, and other
Calibration	Adjustment of a set of code input parameters to maximize the resulting agreement of the code calculations with observations in a specific scenario.
Catastrophic wildfire	A fire that caused at least one death, damaged over 500 structures, or burned over 5,000 acres.
Circuit miles	The total length in miles of separate transmission and/or distribution circuits, regardless of the number of conductors used per circuit (i.e., different phases).
Consequence	The adverse effects from an event, considering the hazard intensity, community exposure, and local vulnerability.

**TABLE PG&E-A-1:
DEFINITION OF TERMS – ALPHABETICAL BY TERM
(CONTINUED)**

Term	Definition
Contact by object ignition likelihood	The likelihood that a non-vegetative object (such as a balloon or vehicle) will contact utility-owned equipment and result in an ignition.
Contact by vegetation ignition likelihood	The likelihood that vegetation will contact utility-owned equipment and result in an ignition.
Contractor	Any individual in the temporary and/or indirect employ of the electrical corporation whose limited hours and/or time-bound term of employment are not considered “full-time” for tax and/or any other purposes.
Critical facilities and infrastructure	Facilities and infrastructure that are essential to public safety and that require additional assistance and advance planning to ensure resiliency during Public Safety Power Shutoff (PSPS) events. These include the following: • Emergency services sector: – Police stations; – Fire stations; – Emergency operations centers; – Public safety answering points (e.g., 9-1-1 emergency services); • Government facilities sector: – Schools; – Jails and prisons; • Health care and public health sector: – Public health departments; – Medical facilities, including hospitals, skilled nursing facilities, nursing homes, blood banks, health care facilities, dialysis centers, and hospice facilities (excluding doctors’ offices and other non-essential medical facilities); • Energy sector: – Public and private utility facilities vital to maintaining or restoring normal service, including, but not limited to, interconnected publicly owned electrical corporations and electric cooperatives; • Water and wastewater systems sector: – Facilities associated with provision of drinking water or processing of wastewater, including facilities that pump, divert, transport, store, treat, and deliver water or wastewater; • Communications sector:

TABLE PG&E-A-1:
DEFINITION OF TERMS – ALPHABETICAL BY TERM
(CONTINUED)

Term	Definition
	– Communication carrier infrastructure, including selective routers, central offices, head ends, cellular switches, remote terminals, and cellular sites; • Chemical sector: – Facilities associated with manufacturing, maintaining, or distributing hazardous materials and chemicals (including Category N-Customers as defined in Decision (D.) 01-06-085); and • Transportation sector: – Facilities associated with transportation for civilian and military purposes: automotive, rail, aviation, maritime, or major public transportation (D.19-05-042 and D.20-05-051).
Customer hours	Total number of customers, multiplied by average number of hours (e.g., of power outage).
Danger tree	Any tree located on or adjacent to a utility right-of-way or facility that could damage utility facilities should it fall where: (1) the tree leans toward the right-of-way, or (2) the tree is defective because of any cause, such as: heart or root rot, shallow roots, excavation, bad crotch, dead or with dead top, deformity, cracks or splits, or any other reason that could result in the tree or main lateral of the tree falling. (California Code of Regulation Title 14 § 895.1)
Data cleaning	Calibration of raw data to remove errors (including typographical and numerical mistakes).
Dead fuel moisture content	Moisture content of dead vegetation, which responds solely to current environmental conditions and is critical in determining fire potential.
Detailed inspection	In accordance with General Order (GO) 165, an inspection where individual pieces of equipment and structures are carefully examined, visually and through routine diagnostic testing, as appropriate, and (if practical and if useful information can be so gathered) opened, and the condition of each is rated and recorded.
Disaster	A serious disruption of the functioning of a community or a society at any scale due to hazardous events interacting with conditions of exposure, vulnerability, and capacity, leading to one or more of the following: human, material, economic, and environmental losses and impacts. The effect of the disaster can be immediate and localized but is often widespread and could last a long time. The effect may test or exceed the capacity of a community or society to cope using its own resources. Therefore, it may require assistance from external sources, which could include neighboring jurisdictions or those at the national or international levels. (United Nations Office for Disaster Risk Reduction [UNDRR].)
Discussion-based exercise	Exercise used to familiarize participants with current plans, policies, agreements, and procedures or to develop new plans, policies,

TABLE PG&E-A-1:
DEFINITION OF TERMS – ALPHABETICAL BY TERM
(CONTINUED)

Term	Definition
	agreements, and procedures. Often includes seminars, workshops, tabletop exercises, and games.
Electrical corporation	Every corporation or person owning, controlling, operating, or managing any electric plant for compensation within California, except where the producer generates electricity on or distributes it through private property solely for its own use or the use of its tenants and not for sale or transmission to others.
Emergency	Any incident, whether natural, technological, or human caused, that requires responsive action to protect life or property but does not result in serious disruption of the functioning of a community or society. (Federal Emergency Management Agency (FEMA)/UNDRR.)
Enhanced inspection	Inspection whose frequency and thoroughness exceed the requirements of a detailed inspection, particularly if driven by risk calculations.
Equipment ignition likelihood	The likelihood that utility-owned equipment will cause an ignition through either normal operation (such as arcing) or failure.
Exercise	An instrument to train for, assess, practice, and improve performance in prevention, protection, response, and recovery capabilities in a risk-free environment. (FEMA.)
Exposure	The presence of people, infrastructure, livelihoods, environmental services and resources, and other high-value assets in places that could be adversely affected by a hazard.
Fire ecology	A scientific discipline concerned with natural processes involving fire in an ecosystem and its ecological effects, the interactions between fire and the abiotic and biotic components of an ecosystem, and the role of fire as an ecosystem process.
Fire Potential Index (FPI)	Landscape scale index used as a proxy for assessing real-time risk of a wildfire under current and forecasted weather conditions.
Fire season	The time of year when wildfires are most likely for a given geographic region due to historical weather conditions, vegetative characteristics, and impacts of climate change. Each electrical corporation defines the fire season(s) across its service territory based on a recognized fire agency definition for the specific region(s) in California.
Frequency	The anticipated number of occurrences of an event or hazard over time.
Frequent PSPS events	Three or more PSPS events per calendar year per line circuit.
Fuel density	Mass of fuel (vegetation) per area that could combust in a wildfire.
Fuel management	Removal or thinning of vegetation to reduce the potential rate of propagation or intensity of wildfires.
Fuel moisture content	Amount of moisture in a given mass of fuel (vegetation), measured as a percentage of its dry weight.

TABLE PG&E-A-1:
DEFINITION OF TERMS – ALPHABETICAL BY TERM
(CONTINUED)

Term	Definition
Full-time employee (FTE)	Any individual in the ongoing and/or direct employ of the electrical corporation whose hours and/or term of employment are considered “full-time” for tax and/or any other purposes.
Game	A simulation of operations that often involves two or more teams, usually in a competitive environment, using rules, data, and procedures designed to depict an actual or assumed real- life situation.
Goals	The electrical corporation’s general intentions and ambitions.
GO 95 nonconformance	Condition of a utility asset that does not meet standards established by GO 95.
Grid hardening	Actions (such as equipment upgrades, maintenance, and planning for more resilient infrastructure) taken in response to the risk of undesirable events (such as outages) or undesirable conditions of the electrical system to reduce or mitigate those events and conditions, informed by an assessment of the relevant risk drivers or factors.
Grid topology	General design of an electric grid, whether looped or radial, with consequences for reliability and ability to support PSPS (e.g., ability to deliver electricity from an additional source).
Hazard	A condition, situation, or behavior that presents the potential for harm or damage to people, property, the environment, or other valued resources.
Hazard tree	See danger tree
High Fire Threat District (HFTD)	Areas of the state designated by the California Public Utilities Commission (CPUC or Commission) as having elevated wildfire risk, where each utility must take additional action (per GO 95, GO 165, and GO 166) to mitigate wildfire risk. (D.17-01-009.)
High Fire Risk Area (HFRA)	Areas that the electrical corporation has deemed at high risk from wildfire, independent of HFTD designation.
Highly rural region	In accordance with 38 CFR 17.701, area with a population of less than seven persons per square mile, as determined by the United States Bureau of the Census. For purposes of the Wildfire Mitigation Plan (WMP), “area” must be defined as a census tract.
High-risk species	Species of vegetation that: (1) have a higher risk of either coming into contact with powerlines or causing an outage or ignition, or (2) are easily ignitable and within close proximity to potential arcing, sparks, and/or other utility equipment thermal failures. The status of species as “high-risk” must be a function of species-specific characteristics, including growth rate; failure rates of limbs, trunk, and/or roots (as compared to other species); height at maturity; flammability; and vulnerability to disease or insects.
High Wind Warning (HWW)	Level of wind risk from weather conditions, as declared by the National Weather Service (NWS). For historical NWS data, refer to the Iowa State University archive of NWS watches/warnings.

TABLE PG&E-A-1:
DEFINITION OF TERMS – ALPHABETICAL BY TERM
(CONTINUED)

Term	Definition
HWW overhead (OH) circuit mile day	Sum of OH circuit miles of utility grid subject to a HWW each day within a given time period, calculated as the number of OH circuit miles under a HWW multiplied by the number of days those miles are under said HWW. For example, if 100 OH circuit miles are under a HWW for one day, and 10 of those miles are under the HWW for an additional day, then the total HWW OH circuit mile days would be 110.
Ignition consequence	The total anticipated adverse effects from an ignition at each location in the electrical corporation service territory. This considers the likelihood that an ignition will transition into a wildfire (wildfire spread likelihood) and the consequences that the wildfire will have on each community it reaches (wildfire consequence).
Ignition likelihood	The total anticipated annualized number of ignitions resulting from utility-owned assets at each location in the electrical corporation service territory. This considers probabilistic weather conditions, type and age of equipment, and potential contact of vegetation and other objects with utility assets.
Ignition probability	The relative possibility that an ignition will occur, quantified as a number between 0 percent (impossibility) and 100 percent (certainty). The higher the probability of an event, the more certainty there is that the event will occur. (Often informally referred to as likelihood or chance.)
Ignition risk	The total anticipated 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 on each community it reaches.
Impact/consequence of ignition	The effect or outcome of a wildfire ignition upon objectives that may be expressed by terms including, although not limited to, maintaining health and safety, ensuring reliability, and minimizing economic and/or environmental damage.
Incident command system (ICS)	A standardized on-scene emergency management construct. It is specifically designed to provide an integrated organizational structure that reflects the complexity and demands of single or multiple incidents, without being hindered by jurisdictional boundaries. The ICS is the combination of facilities, equipment, personnel, procedures, and communications operating within a common organizational structure, designed to aid in the management of resources during incidents.
Initiative	Measure or activity, either proposed or in process, designed to reduce the consequences and/or probability of wildfire or PSPS.

TABLE PG&E-A-1:
DEFINITION OF TERMS – ALPHABETICAL BY TERM
(CONTINUED)

Term	Definition
Integrated public alert warning system (IPAWS)	System allowing the President to send a message to the American people quickly and simultaneously through multiple communications pathways in a national emergency. IPAWS also is available to United States federal, state, local, territorial, and tribal government officials to alert the public via the Emergency Alert System, Wireless Emergency Alerts, National Oceanic and Atmospheric Administration Weather Radio, and other NWS dissemination channels; the internet; existing unique warning systems; and emerging distribution technologies.
Invasive species	A species: (1) that is non-native (or alien) to the ecosystem under consideration and (2) whose introduction causes or is likely to cause economic or environmental harm or harm to human health.
Level 1 finding	In accordance with GO 95, an immediate safety and/or reliability risk with high probability for significant impact.
Level 2 finding	In accordance with GO 95, a variable safety and/or reliability risk (non-immediate and with high to low probability for significant impact).
Level 3 finding	In accordance with GO 95, an acceptable safety and/or reliability risk.
Limited English proficiency (LEP) population	Population with limited English working proficiency based on the International Language Roundtable scale.
Line miles	The number of miles of transmission and/or distribution conductors, including the length of each phase and parallel conductor segment.
Live fuel moisture content	Moisture content within living vegetation, which can retain water longer than dead fuel.
Locally relevant	In disaster risk management, generally understood as the scale at which disaster risk strategies and initiatives are considered the most effective at achieving desired outcomes. This tends to be the level closest to impacting residents and communities, reducing existing risks, and building capacity, knowledge, and normative support. Locally relevant scales, conditions, and perspectives depend on the context of application.
Match-drop simulation	Wildfire simulation method forecasting propagation and consequence/impact based on an arbitrary ignition.
Memorandum of Agreement (MOA)	A document of agreement between two or more agencies establishing reciprocal assistance to be provided upon request (and if available from the supplying agency) and laying out the guidelines under which this assistance will operate. It can also be a cooperative document in which parties agree to work together on an agreed-upon project or meet an agreed objective.
Mitigation	Activities to reduce the loss of life and property from natural and/or human-caused disasters by avoiding or lessening the impact of a disaster and providing value to the public by creating safer communities.

TABLE PG&E-A-1:
DEFINITION OF TERMS – ALPHABETICAL BY TERM
(CONTINUED)

Term	Definition
Model uncertainty	The amount by which a calculated value might differ from the true value when the input parameters are known (i.e., limitation of the model itself based on assumptions).
Multi-attribute value function (MAVF)	Risk calculation methodology introduced during CPUC's Safety Model Assessment Proceedings and Risk Assessment and Mitigation Phase proceedings. This methodology is established in D.18-12-014 but may be subject to change pursuant to R.20-07-013.
Mutual aid	Voluntary aid and assistance by the provision of services and facilities, including but not limited to electrical corporations, communication, and transportation. Mutual aid is intended to provide adequate resources, facilities, and other support to electrical corporations whenever their own resources prove inadequate to cope with a given situation.
National Incident Management System (NIMS)	A systematic, proactive approach to guide all levels of government, nongovernment organizations, and the private sector to work together to prevent, protect against, mitigate, respond to, and recover from the effects of incidents. NIMS provides stakeholders across the whole community with the shared vocabulary, systems, and processes to successfully deliver the capabilities described in the National Preparedness System. NIMS provides a consistent foundation for dealing with all incidents, ranging from daily occurrences to incidents requiring a coordinated federal response.
Near miss	Term previously used for an event with probability of ignition (now "Risk event").
Objectives	Specific, measurable, achievable, realistic, and timely outcomes for the overall WMP strategy, or mitigation initiatives and activities that a utility can implement to satisfy the primary goals and subgoals of the WMP program.
Operations-based exercise	Type of exercise that validates plans, policies, agreements, and procedures; clarifies roles and responsibilities; and identifies resource gaps in an operational environment. Often includes drills, functional exercises, and full-scale exercises.
Overall utility risk	The comprehensive risk due to both wildfire and PSPS incidents across a utility's territory; the aggregate potential of adverse impacts to people, property, critical infrastructure, or other valued assets in society.
Overall utility risk, ignition risk	See Ignition risk.
Overall utility risk, PSPS risk	See PSPS risk.
Parameter uncertainty	The amount by which a calculated value might differ from the true value based on unknown input parameters. (Adapted from Society of Fire Protection Engineers [SFPE] guidance.)
Patrol inspection	In accordance with GO 165, a simple visual inspection of applicable utility equipment and structures designed to identify obvious structural problems and hazards. Patrol inspections may be carried out in the course of other company business.

TABLE PG&E-A-1:
DEFINITION OF TERMS – ALPHABETICAL BY TERM
(CONTINUED)

Term	Definition
Performance metric	A quantifiable measurement that is used by an electrical corporation to indicate the extent to which its WMP is driving performance outcomes.
Population density	Population density is calculated using the American Community Survey (ACS) 1-year estimate for the corresponding year or, for years with no such ACS estimate available, the estimate for the immediately preceding year.
Preparedness	A continuous cycle of planning, organizing, training, equipping, exercising, evaluating, and taking corrective action in an effort to ensure effective coordination during incident response. Within the NIMS, preparedness focuses on planning, procedures and protocols, training and exercises, personnel qualification and certification, and equipment certification.
Priority essential services	Critical first responders, public safety partners, critical facilities and infrastructure, operators of telecommunications infrastructure, and water electrical corporations/agencies.
Property	Private and public property, buildings and structures, infrastructure, and other items of value that may be destroyed by wildfire, including both third-party property and utility assets.
Protective equipment and device settings	The electrical corporation's procedures for adjusting the sensitivity of grid elements to reduce wildfire risk, other than automatic reclosers (such as circuit breakers, switches, etc.). For example, PG&E's "Enhanced Powerline Safety Settings."
PSPS consequence	The total anticipated adverse effects of a PSPS for a community. This considers the PSPS exposure potential and inherent PSPS vulnerabilities of communities at risk.
PSPS event	The period from notification of the first public safety partner of a planned public safety PSPS to re-energization of the final customer.
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.
PSPS likelihood	The likelihood of a PSPS being required by a utility given a probabilistic set of environmental conditions.
PSPS risk	The total anticipated annualized impacts from a PSPS event at a specific location. This considers the likelihood a PSPS event will be required due to environmental conditions exceeding design conditions and the potential consequences—considering exposure potential and vulnerability—of the PSPS event for each affected community.
Public safety partners	First/emergency responders at the local, state, and federal levels; water, wastewater, and communication service providers; Community Choice Aggregators; affected publicly owned electrical corporations/electrical cooperatives; tribal governments; Energy Safety; the Commission; the California Office of Emergency Services; and California Department of Forestry and Fire Protection.

TABLE PG&E-A-1:
DEFINITION OF TERMS – ALPHABETICAL BY TERM
(CONTINUED)

Term	Definition
Red Flag Warning (RFW)	Level of wildfire risk from weather conditions, as declared by the NWS. For historical NWS data, refer to the Iowa State University archive of NWS watches/warnings.
RFW OH circuit mile day	Sum of OH circuit miles of utility grid subject to RFW each day within a given time period, calculated as the number of OH circuit miles under RFW multiplied by the number of days those miles are under said RFW. For example, if 100 OH circuit miles are under RFW for one day, and 10 of those miles are under RFW for an additional day, then the total RFW OH circuit mile days would be 110.
Risk	A measure of the anticipated adverse effects from a hazard considering the consequences and frequency of the hazard occurring.
Risk component	A part of an electric corporation's risk analysis framework used to determine overall utility risk.
Risk evaluation	The process of comparing the results of a risk analysis with risk criteria to determine whether the risk and/or its magnitude is acceptable or tolerable. (International Organization for Standardization (ISO) 31000:2009.)
Risk event	An event with probability of ignition, such as wire down, contact with objects, line slap, event with evidence of heat generation, or other event that causes sparking or has the potential to cause ignition. The following all qualify as risk events: • Ignitions; • Outages not caused by vegetation; • Outages caused by vegetation; • Wire-down events; • Faults; and • Other events with potential to cause ignition.
Risk management	Systematic application of management policies, procedures, and practices to the tasks of communication, consultation, establishment of context, and identification, analysis, evaluation, treatment, monitoring, and review of risk. (ISO 31000.)
Rule	Section of Pub. Util. Code requiring a particular activity or establishing a particular threshold.
Rural region	In accordance with GO 165, area with a population of less than 1,000 persons per square mile, as determined by the United States (U.S.) Bureau of the Census. For purposes of the WMP, "area" must be defined as a census tract.
Seminar	An informal discussion, designed to orient participants to new or updated plans, policies, or procedures (e.g., to review a new external communications standard operating procedure).

TABLE PG&E-A-1:
DEFINITION OF TERMS – ALPHABETICAL BY TERM
(CONTINUED)

Term	Definition
Sensitivity analysis	Process used to determine the relationships between the uncertainty in the independent variables (“input”) used in an analysis and the uncertainty in the resultant dependent variables (“output”). (SFPE guidance.)
Slash	Branches or limbs less than four inches in diameter, and bark and split products debris left on the ground as a result of utility vegetation management. (This definition is consistent with California PRC Section 4525.7.)
Span	The space between adjacent supporting poles or structures on a circuit consisting of electric lines and equipment. “Span level” refers to asset-scale granularity.
Tabletop exercise (TTX)	A discussion-based exercise intended to stimulate discussion of various issues regarding a hypothetical situation. Tabletop exercises can be used to assess plans, policies, and procedures or to assess types of systems needed to guide the prevention of, response to, or recovery from a defined incident.
Target	A forward-looking, quantifiable measurement of work to which an electrical corporation commits to in its WMP. Electrical corporations will show progress toward completing targets in subsequent reports, including Quarterly Data Reports and WMP Updates.
Trees with strike potential	Trees that could either “fall in” to a power line or have branches detach and “fly in” to contact a power line in high-wind conditions.
Uncertainty	The amount by which an observed or calculated value might differ from the true value. For an observed value, the difference is “experimental uncertainty”; for a calculated value, it is “model” or “parameter uncertainty.” (Adapted from SFPE guidance.)
Urban region	In accordance with GO 165, area with a population of more than 1,000 persons per square mile, as determined by the U.S. Bureau of the Census. For purposes of the WMP, “area” must be defined as a census tract.
Utility-related ignition	See reportable ignition.
Validation	Process of determining the degree to which a calculation method accurately represents the real world from the perspective of the intended uses of the calculation method without modifying input parameters based on observations in a specific scenario. (Adapted from ASTM E 1355.)
Vegetation management (VM)	Trimming and removal of trees and other vegetation at risk of contact with electric equipment.
Verification	Process to ensure that a model is working as designed, that is, that the equations are being properly solved. Verification is essentially a check of the mathematics. (SFPE guidance.)
Vulnerability	The propensity or predisposition of a community to be adversely affected by a hazard, including the characteristics of a person, group, or service and their situation that influences their capacity to anticipate, cope with, resist, and recover from the adverse effects of a hazard.

TABLE PG&E-A-1:
DEFINITION OF TERMS – ALPHABETICAL BY TERM
(CONTINUED)

Term	Definition
Wildfire consequence	The total anticipated adverse effects from a wildfire on a community that is reached. This considers the wildfire hazard intensity, the wildfire exposure potential, and the inherent wildfire vulnerabilities of communities at risk.
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. This may include direct or indirect impacts, as well as short- and long-term impacts.
Wildfire 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 mitigation strategy	Overview of the key mitigation initiatives at enterprise level and component level across the electrical corporation's service territory, including interim strategies where long-term mitigation initiatives have long implementation timelines. This includes a description of the enterprise-level monitoring and evaluation strategy for assessing overall effectiveness of the WMP.
Wildfire risk	See Ignition risk.
Wildfire spread likelihood	The likelihood that a fire with a nearby but unknown ignition point will transition into a wildfire and will spread to a location in the service territory based on a probabilistic set of weather profiles, vegetation, and topography.
Wildland-urban interface (WUI)	The line, area, or zone where structures and other human development meet or intermingle with undeveloped wildland or vegetation fuels (National Wildfire Coordinating Group). Enforcement agencies also designate the WUI as the area at significant risk from wildfires, established pursuant to Title 24, Part 2, Chapter 7A.
Wire down	Instance where an electric transmission or distribution conductor is broken and falls from its intended position to rest on the ground or a foreign object.
Work order	A prescription for asset or vegetation management activities resulting from asset or vegetation management inspection findings.
Workshop	Discussion that resembles a seminar but is employed to build specific products, such as a draft plan or policy (e.g., a multi-year training and exercise plan).

Appendix A.2 – Definitions of Initiatives – by Category

**TABLE PG&E-A-2:
DEFINITIONS OF INITIATIVES – BY CATEGORY**

Category	Section #	Initiative	Definition
Overview of the Service Territory	5.4.5	Environmental compliance and permitting	Development and implementation of process and procedures to ensure compliance with applicable environmental laws, regulations, and permitting related to the implementation of the WMP.
Risk Methodology and Assessment	6	Risk Methodology and Assessment	Development and use of tools and processes to assess the risk of wildfire and PSPS across an electrical corporation's service territory.
Wildfire Mitigation Strategy Development	7	Wildfire Mitigation Strategy Development	Development and use of processes for deciding on a portfolio of mitigation initiatives to achieve maximum feasible risk reduction and that meet the goals of the WMP.
Grid Design, Operations, and Maintenance	8.1.2.1	Covered conductor installation	Installation of covered or insulated conductors to replace standard bare or unprotected conductors (defined in accordance with GO 95 as supply conductors, including but not limited to lead wires, not enclosed in a grounded metal pole or not covered by: a "suitable protective covering" (in accordance with Rule 22.8), grounded metal conduit, or grounded metal sheath or shield). In accordance with GO 95, conductor is defined as a material suitable for: (1) carrying electric current, usually in the form of a wire, cable or bus bar, or (2) transmitting light in the case of fiber optics; insulated conductors as those which are surrounded by an insulating material (in accordance with Rule 21.6), the dielectric strength of which is sufficient to withstand the maximum difference of potential at normal operating voltages of the circuit without breakdown or puncture; and suitable protective covering as a covering of wood or other non-conductive material having the electrical insulating efficiency (12 kilovolts (kV)/in. dry) and impact strength (20 foot-pounds) of 1.5 inches of redwood or other material meeting the requirements of Rule 22.8-A, 22.8-B, 22.8-C or 22.8-D.

TABLE PG&E-A-2:
DEFINITIONS OF INITIATIVES – BY CATEGORY
(CONTINTUED)

Category	Section #	Initiative	Definition
Grid Design, Operations, and Maintenance	8.1.2.2	Undergrounding of electric lines and/or equipment	Actions taken to convert overhead electric lines and/or equipment to underground electric lines and/or equipment (i.e., located underground and in accordance with GO 128).
Grid Design, Operations, and Maintenance	8.1.2.3	Distribution pole replacements and reinforcements	Remediation, adjustments, or installations of new equipment to improve or replace existing distribution poles (i.e., those supporting lines under 65 kV), including with equipment such as composite poles manufactured with materials reduce ignition probability by increasing pole lifespan and resilience against failure from object contact and other events.
Grid Design, Operations, and Maintenance	8.1.2.4	Transmission pole/tower replacements and reinforcements	Remediation, adjustments, or installations of new equipment to improve or replace existing transmission towers (e.g., structures such as lattice steel towers or tubular steel poles that support lines at or above 65 kV).
Grid Design, Operations, and Maintenance	8.1.2.5	Traditional overhead hardening	Maintenance, repair, and replacement of capacitors, circuit breakers, cross-arms, transformers, fuses, and connectors (e.g., hot line clamps) with the intention of minimizing the risk of ignition.
Grid Design, Operations, and Maintenance	8.1.2.6	Emerging grid hardening technology installations and pilots	Development, deployment, and piloting of novel grid hardening technology.
Grid Design, Operations, and Maintenance	8.1.2.7	Microgrids	Development and deployment of microgrids that may reduce the risk of ignition, risk from PSPS, and wildfire consequence. "Microgrid" is defined by Pub. Util. Section 8370(d).
Grid Design, Operations, and Maintenance	8.1.2.8	Installation of system automation equipment	Installation of electric equipment that increases the ability of the electrical corporation to automate system operation and monitoring, including equipment that can be adjusted remotely such as automatic reclosers (switching devices designed to detect and interrupt momentary faults that can reclose automatically and detect if a fault remains, remaining open if so).
Grid Design, Operations, and Maintenance	8.1.2.9	Line removals (in HFTD)	Removal of overhead lines to minimize the risk of ignition due to the design, location, or configuration of electric equipment in HFTDs.

TABLE PG&E-A-2:
DEFINITIONS OF INITIATIVES – BY CATEGORY
(CONTINTUED)

Category	Section #	Initiative	Definition
Grid Design, Operations, and Maintenance	8.1.2.10	Other grid topology improvements to minimize risk of ignitions	Actions taken to minimize the risk of ignition due to the design, location, or configuration of electric equipment in HFTDs not covered by another initiative.
Grid Design, Operations, and Maintenance	8.1.2.11	Other grid topology improvements to mitigate or reduce PSPS events	Actions taken to mitigate or reduce PSPS events in terms of geographic scope and number of customers affected not covered by another initiative.
Grid Design, Operations, and Maintenance	8.1.2.12	Other technologies and systems not listed above	Other grid design and system hardening actions which the electrical corporation takes to reduce its ignition and PSPS risk not otherwise covered by other initiatives in this section.
Grid Design, Operations, and Maintenance	8.1.3.1	Asset inspections	Inspections of overhead electric transmission lines, equipment, and right-of-way.
Grid Design, Operations, and Maintenance	8.1.4	Equipment maintenance and repair	Remediation, adjustments, or installations of new equipment to improve or replace existing connector equipment, such as hotline clamps.
Grid Design, Operations, and Maintenance	8.1.5	Asset management and inspection enterprise system(s)	Operation of and support for centralized asset management and inspection enterprise system(s) updated based upon inspection results and activities such as hardening, maintenance, and remedial work.
Grid Design, Operations, and Maintenance	8.1.6	Quality assurance/ quality control	Establishment and function of audit process to manage and confirm work completed by employees or contractors, including packaging Quality Assurance/Quality Control (QA/QC) information for input to decision-making and related integrated workforce management processes.
Grid Design, Operations, and Maintenance	8.1.7	Open work orders	Actions taken to manage the electrical corporation's open work orders resulting from inspections that prescribe asset management activities.
Grid Design, Operations, and Maintenance	8.1.8.1	Equipment Settings to Reduce Wildfire Risk	The electrical corporation's procedures for adjusting the sensitivity of grid elements to reduce wildfire risk.
Grid Design, Operations, and Maintenance	8.1.8.2	Grid Response Procedures and Notifications	The electrical corporation's procedures it uses to respond to faults, ignitions, or other issues detected on its grid that may result in a wildfire.

TABLE PG&E-A-2:
DEFINITIONS OF INITIATIVES – BY CATEGORY
(CONTINTUED)

Category	Section #	Initiative	Definition
Grid Design, Operations, and Maintenance	8.1.8.3	Personnel Work Procedures and Training in Conditions of Elevated Fire Risk	Work activity guidelines that designate what type of work can be performed during operating conditions of different levels of wildfire risk. Training for personnel on these guidelines and the procedures they prescribe, from normal operating procedures to increased mitigation measures to constraints on work performed.
Grid Design, Operations, and Maintenance	8.1.9	Workforce Planning	Programs to ensure that the electrical corporation has qualified asset personnel and to ensure that both employees and contractors tasked with asset management responsibilities are adequately trained to perform relevant work.
Vegetation Management and Inspection	8.2.2.1	Vegetation inspections	Inspections of vegetation around and adjacent to electrical facilities and equipment that may be hazardous by growing, blowing, or falling into electrical facilities or equipment.
Vegetation Management and Inspection	8.2.3.1	Pole clearing	Plan and execution of vegetation removal around poles per PRC Section 4292 and outside the requirements of PRC Section 4292 (e.g., pole clearing performed outside of the State Responsibility Area).
Vegetation Management and Inspection	8.2.3.2	Wood and slash management	Actions taken to manage all downed wood and “slash” generated from vegetation management activities.
Vegetation Management and Inspection	8.2.3.3	Clearance	Actions taken after inspection to ensure that vegetation does not encroach upon electrical equipment and facilities, such as tree trimming.
Vegetation Management and Inspection	8.2.3.4	Fall-in mitigation	Actions taken to identify and remove or otherwise remediate trees that pose a high risk of failure
Vegetation Management and Inspection	8.2.3.5	Substation defensible space	Actions taken to reduce ignition probability and wildfire consequence (WFC) due to contact with substation equipment.
Vegetation Management and Inspection	8.2.3.6	High-risk species	Actions taken to reduce the ignition probability and wildfire consequence attributable to high-risk species of vegetation.

TABLE PG&E-A-2:
DEFINITIONS OF INITIATIVES – BY CATEGORY
(CONTINTUED)

Category	Section #	Initiative	Definition
Vegetation Management and Inspection	8.2.3.7	Fire-resilient rights-of-way	Actions taken to promote vegetation communities that are sustainable, fire-resilient, and compatible with the use of the land as an electrical corporation right-of-way.
Vegetation Management and Inspection	8.2.3.8	Emergency response vegetation management	Planning and execution of vegetation activities in response to emergency situations including weather conditions that indicate an elevated fire threat and post-wildfire service restoration.
Vegetation Management and Inspection	8.2.4	Vegetation management enterprise system	Operation of and support for centralized vegetation management and inspection enterprise system(s) updated based upon inspection results and activities such as hardening, maintenance, and remedial work.
Vegetation Management and Inspection	8.2.5	Quality assurance/ quality control	Establishment and function of audit process to manage and confirm work completed by employees or contractors, including packaging QA/QC information for input to decision-making and related integrated workforce management processes.
Vegetation Management and Inspection	8.2.6	Open work orders	Actions taken to manage the electrical corporation's open work orders resulting from inspections that prescribe vegetation management activities.
Vegetation Management and Inspection	8.2.7	Workforce planning	Programs to ensure that the electrical corporation has qualified vegetation management personnel and to ensure that both employees and contractors tasked with vegetation management responsibilities are adequately trained to perform relevant work.
Situational Awareness and Forecasting	8.3.2	Environmental monitoring systems	Development and deployment of systems which measure environmental characteristics, such as fuel moisture, air temperature, and velocity.
Situational Awareness and Forecasting	8.3.3	Grid monitoring systems	Development and deployment of systems that checks the operational conditions of electrical facilities and equipment and detects such things as faults, failures, and recloser operations.
Situational Awareness and Forecasting	8.3.4	Ignition detection systems	Development and deployment of systems which discover or identify the presence or existence of an ignition, such as cameras.

TABLE PG&E-A-2:
DEFINITIONS OF INITIATIVES – BY CATEGORY
(CONTINTUED)

Category	Section #	Initiative	Definition
Situational Awareness and Forecasting	8.3.5	Weather forecasting	Development methodology for forecast of weather conditions relevant to electrical corporation operations, forecasting weather conditions and conducting analysis to incorporate into utility decision- making, learning and updates to reduce false positives and false negatives of forecast PSPS conditions.
Situational Awareness and Forecasting	8.3.6	Fire potential index	Calculation and application of a landscape scale index used as a proxy for assessing real-time risk of a wildfire under current and forecasted weather conditions.
Emergency Preparedness	8.4.2	Emergency preparedness plan	Development and integration of wildfire- and PSPS-specific emergency strategies, practices, policies, and procedures into the electrical corporation's overall emergency plan based on the minimum standards described in GO 166.
Emergency Preparedness	8.4.3	External collaboration and coordination	Actions taken to coordinate wildfire and PSPS emergency preparedness with relevant public safety partners including the state, cities, counties, and tribes.
Emergency Preparedness	8.4.4	Public emergency communication strategy	Development and integration of a 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.
Emergency Preparedness	8.4.5	Preparedness and planning for service restoration	Development and integration of the electrical corporation's plan to restore service after an outage due to a wildfire or PSPS event.
Emergency Preparedness	8.4.6	Customer support in wildfire and PSPS emergencies	Development and deployment of programs, systems, and protocols to support residential and non-residential customers in wildfire emergencies and PSPS events.
Community Outreach and Engagement	8.5.2	Public outreach and education awareness program	Development and deployment of public outreach and education awareness program(s) for wildfires; outages due to wildfires, PSPS events, and protective equipment and device settings; service restoration before, during, and after the incidents and vegetation management.

**TABLE PG&E-A-2:
DEFINITIONS OF INITIATIVES – BY CATEGORY
(CONTINTUED)**

Category	Section #	Initiative	Definition
Community Outreach and Engagement	8.5.3	Engagement with access and functional needs populations	Actions taken understand, evaluate, design, and implement wildfire and PSPS risk mitigation strategies, policies, and procedures specific to access and functional needs customers.
Community Outreach and Engagement	8.5.4	Collaboration on local wildfire mitigation planning	Development and integration of plans, programs, and/or policies for collaborating with communities on local wildfire mitigation planning, such as wildfire safety elements in general plans, community wildfire protection plans, and local multi- hazard mitigation plans.
Community Outreach and Engagement	8.5.5	Best practice sharing with other utilities	Development and integration of an electrical corporation's policy for sharing best practices and collaborating with other electrical corporations on technical and programmatic aspects of its WMP program.

Appendix A.3 – PG&E Glossary of Additional Defined Terms

TABLE PG&E-A-3:
PG&E GLOSSARY OF ADDITIONAL DEFINED TERMS – ALPHABETICAL BY TERM

Term	Definition
2020 General Rate Case (GRC) Decision	Decision Addressing the Test Year 2020 GRC of PG&E: Decision (D.) 20-12-005.
2020 Risk Assessment and Mitigation Phase (RAMP) Report	PG&E's 2020 Risk Assessment and Mitigation Phase Report, filed June 30, 2020. Application (A). 20-06-012.
2022 Enterprise Risk Model	Bow Tie-based Wildfire risk model for distribution and transmission system.
2023 GRC	PG&E's Test Year 2023 GRC: A.21-06.021
Bow-Tie	Methodology to evaluate risk events, consistent with the Safety Model and Assessment Proceeding framework.
Catastrophic Fire Behavior (CFB)	The CFB is determined using Technosylva's fire spread modeling. Technosylva inputs PG&E weather data and then runs over 100 million fire spread simulations creating a dataset of potential consequence of new ignitions. The use of CFB helps PG&E identify areas where the potential consequence from an ignition is high, but where the Ignition Probably Weather (IPW) score may be low due to high circuit resiliency.
Catastrophic Fire Probability (CFP)	The CFP Model is the primary method used to determine if PSPS is necessary. This model combines the probability of fire ignitions due to weather impacting the electric system with the probability that a fire will be catastrophic if it starts.
Consequence of Risk Event (CoRE)	Consequence refers to the impact from an event in terms of damage and/or hazard posed to the natural and built environment. The CoRE models use a range of data to assess the consequence of the predicted event from the likelihood (LoRE) side of the model.
Constraints	Constraints can include, but are not limited to, environmental delays, customer interference, permitting delays/restrictions or operational holds, weather conditions, active wildfire, and accessibility into the area.
Corrective Action Program	Process for identifying, evaluating, resolving, and tracking actual or potential issues, problems, failures, nonconformities, concerns, and opportunities for improvement (collectively, called CAP issues) based on probability of occurrence.
Customer Average Interruption Duration Index (CAIDI)	CAIDI measures the average duration of a single sustained outage (i.e., an outage that lasted for longer than 5 minutes) that a customer experienced and is calculated as a weighted average by the Total Customer Minutes divided by the Total Customers impacted.

TABLE PG&E-A-3:
PG&E GLOSSARY OF ADDITIONAL DEFINED TERMS – ALPHABETICAL BY TERM (CONTINUED)

Term	Definition
Customer Minutes Interrupted (CMI)	The number of minutes a customer is without service during a Public Safety Power Shutoff (PSPS) event.
Destructive Fire	A fire that destroys 100 or more structures but does not result in a serious injury or fatality.
Distribution	Electric facilities that have a voltage below 60 kilovolt (kV).
External Factors	External Factors represent reasonable circumstances which may impact execution against targets, objectives, other work, or performance metrics including, but not limited to, physical conditions, landholder refusals, environmental delays, 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.
Failure Mode and Effects Analysis (FMEA)	A step-by-step approach for identifying all possible failures in a design, a manufacturing or assembly process, or a product or service.
Fire Behavior Index (FBI)	A scale of 1 to 5 that captures fire severity as a function of flame length (intensity of burn) and rate of spread. FBI of 3 or greater is expected to require aggressive suppression.
Fire Index Area	A geographical area over which fire danger determinations are produced.
Fire Index Rating	A rating to determine the risk of fire and its likely behavior. Its calculation and scale from R1 to R5-Plus considers fuel moisture, humidity, wind speed, air temperature, and historical fire occurrence. These ratings are as follows: • 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 the use of some equipment and open flames is not permitted. • R5-Plus: The greatest level of fire danger where rapidly moving, catastrophic wildfires are possible. This is typically when fire danger is Extreme, “plus” there are high-risk weather triggers (e.g., strong winds). PSPS triggering event is an example.
Fire Potential Index R Score	See Fire Index Ratings R1 thru R5-Plus.
Fire Return Interval (FRI)	Synonymous with fire interval, fire free interval, and inter-fire interval, which refers to the elapsed time between consecutive fires that burn a given point on the landscape (e.g., 10 years/fire).

TABLE PG&E-A-3:
PG&E GLOSSARY OF ADDITIONAL DEFINED TERMS – ALPHABETICAL BY TERM (CONTINUED)

Term	Definition
Fire Season	May to November of each calendar year. This generally aligns with CalFire definition and the historical trend of wildfire activities.
Fire Weather	The danger ratings produced by the Fire Potential Index (FPI). The FPI Model combines fire weather parameters (wind speed, temperature, and vapor pressure deficit), dead and live fuel moisture data, topography, and fuel model data to predict the probability of large and/or catastrophic fires.
Flame Length	Flame length is the distance between the flame tip and the midpoint of the flame depth at the base of the flame. Flame length is an observable, measurable indicator of fire line intensity.
Fragility Curve	Represents the probability of failure (Pf) for any value of a demand parameter.
Hazard	Hazards represent a forcing function that cause asset failure depending on the condition of the asset.
High Fire Risk Area (HFRA) map	The HFRA Map considers catastrophic fire risk factors and utility infrastructure and was developed by considering incremental changes to the HFTD map boundaries to add areas where risk factors for the potential of catastrophic fire from utility infrastructure ignition during offshore wind events is higher.
IPW	The IPW Model is a machine learning model that uses ten or more years of weather data, outage, and historical ignition data to determine the likelihood of an outage for specific circuits during past weather events. The model also uses historical data to identify the outage causes.
Large Fire	A fire that burns 300 or more acres but does not meet the definition of a Destructive or Catastrophic fire.
Likelihood of Risk Event (LoRE)	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.
Maximum Entropy	The name given to a family of models that seek to differentiate between the characteristics of locations that have hosted grid events and those that have not.
Mitigation (Mitigation Initiative)	A measure or activity proposed or in process that is designed to reduce the impact/consequences and/or the likelihood/probability of a risk event.
Pixel	A 100 meter (m.) x 100 m. location along the grid.
PSPS Consequence	Calculated based on the backcast of PSPS impact based on current PSPS protocols.
PSPS Consequence Model	Projects the impacts and benefits of performing PSPS activities at the circuit or circuit segment level (formerly known as Circuit Protection Zones).
PSPS Likelihood	Estimated by applying the current PSPS protocols against historical climatological dataset informed by two meteorology models (FPI and IPW).

TABLE PG&E-A-3:
PG&E GLOSSARY OF ADDITIONAL DEFINED TERMS – ALPHABETICAL BY TERM (CONTINUED)

Term	Definition
PSPS Potentially Impacted Customer (PIC)	A risk scenario to account for customers in HFTD and HFRA who could be impacted by PSPS despite not being in the historical backcast.
PSPS Risk-Benefit Tool	PG&E's PSPS Risk-Benefit Tool addresses the CPUC's requirements that California IOUs quantify the risk and benefits associated with initiating or not initiating a PSPS event for our customers.
Public Safety Specialist (PSS)	PG&E PSS team members with extensive, local wildfire operations experience. Many had a previous career with CAL FIRE or other fire agencies.
Random Forest	Random forests or random decision forests is an ensemble learning method for classification, regression and other tasks that operates by constructing a multitude of decision trees at training time.
Rate of Spread	The speed with which the fire is moving away from the site of origin measured in Chains (66 feet) per hour.
Risk Driver	Direct causes that lead to a risk event and determine the likelihood or frequency of a risk event. Risk drivers include external events (such as vegetation contact driver) and characteristics inherent to the assets or systems (such as equipment/facility failure) which contribute to the risk event.
S-MAP Settlement Agreement	The Safety Model Assessment Proceeding (S-MAP) Settlement Agreement approved by the CPUC in D.18-12-014.
Safety and Infrastructure Protection Team (SIPT)	SIPT crews consist of two to three International Brotherhood of Electrical Workers represented employees 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.
Sub-driver	A more detailed breakdown of a risk driver.
Technosylva fire spread simulation	Computerized simulations of wildfire behavior given an ignition at a location on a particular date. PG&E works with Technosylva, a vendor of fire simulation software whose outcomes are based on available fuels, topography, and weather, and structure and population data.
Threat	Represent degradation to the initial condition or strength of assets. Threats impact the condition of the asset such as corrosion, wood decay, and wear.
Transmission	Electric facilities that have a voltage that is 60 kV or above.
Transmission Operability Assessment Model	Used to assess physical condition of Transmission facilities for operational and planning decisions.
WFC Model	Wildland fire simulation model to estimate propagation and consequences of ignitions.
Wildfire Distribution Risk Model	Wildfire risk-based model for overhead Distribution system.

TABLE PG&E-A-3:
PG&E GLOSSARY OF ADDITIONAL DEFINED TERMS – ALPHABETICAL BY TERM
(CONTINUED)

Term	Definition
Wildfire Transmission Risk Model	Wildfire risk-based model for overhead Transmission system. This model is also known as the Transmission Composite Model.

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APPENDIX B

SUPPORTING DOCUMENTATION FOR RISK METHODOLOGY AND ASSESSMENT DEFINITIONS

Appendix B – Supporting Documentation for Risk Methodology and Assessment Definitions

Appendix B.1 – Summary Documentation

The electrical corporation must provide high-level information on the calculation of each risk and risk component used in its risk analysis. The summary documentation must include each of the following:

- *High-level bow tie schematic showing the inputs, outputs, and interaction between risk components in the format shown in Figure PG&E-B-1. An example is provided below.*
- *High-level calculation procedure schematic in the format shown in Figure PG&E-B-2. This schematic must show the logical flow from input data to outputs, including separate items for any intermediate calculations in models or sub-models and any input from subject matter experts.*
- *High-level narrative describing the calculation procedure in a concise executive summary. This narrative must include the following:*
  - *Purpose of the calculation/model;*
  - *Assumptions and limitations;*
  - *Description of the calculation procedure shown in the bow tie and high-level schematics;*
  - *Description of how outputs will be characterized and presented (e.g., visualization) to decision makers; and*
  - *Concise description and timeline of planned changes to the calculation procedure over the triennial Wildfire Mitigation Plan (WMP) cycle, including any key improvements from the Energy Safety Wildfire Risk Modeling Working Group and plans to align with the consensus Risk Modeling Requirements by January 1, 2024.*

Below, PG&E provides the requested, high-level model and calculation schematics. We also provide the high-level narrative describing the model calculation procedures pursuant to Energy Safety's instructions. Additional modeling information is found in Section 6 of the 2023 WMP.

Appendix B.2 – High-Level Bow Tie Schematics

**FIGURE PG&E-B-1:
IGNITION PROBABILITY MODEL BOW-TIE**

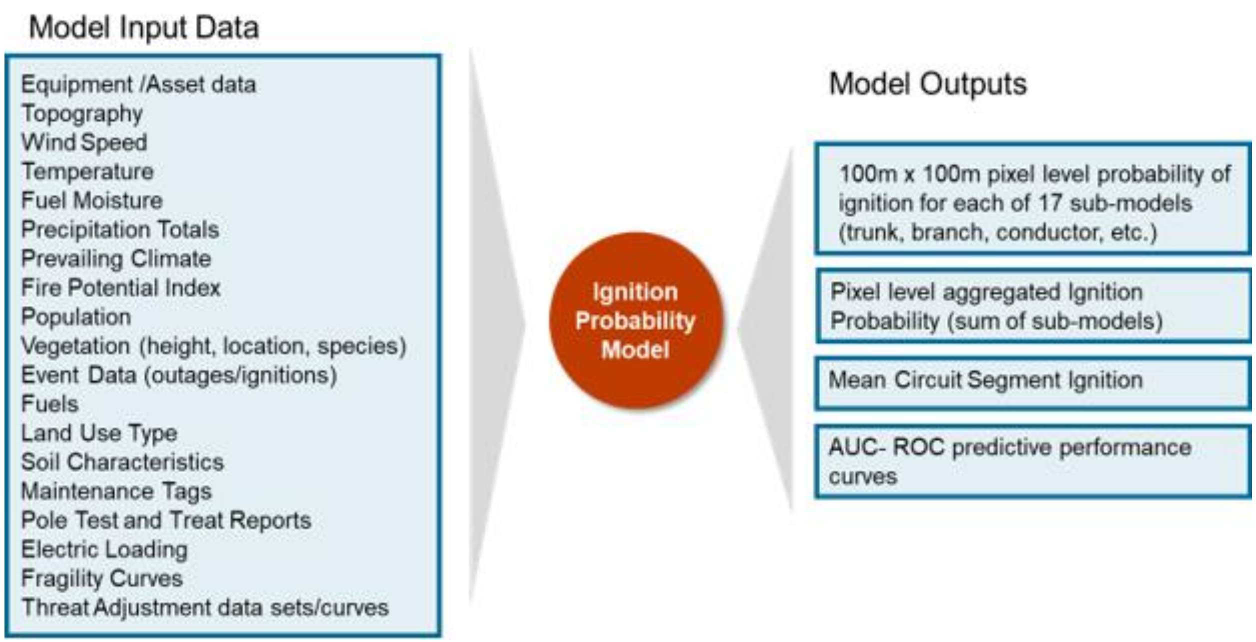


FIGURE PG&E-B-2:
WILDFIRE CONSEQUENCE MODEL BOW-TIE

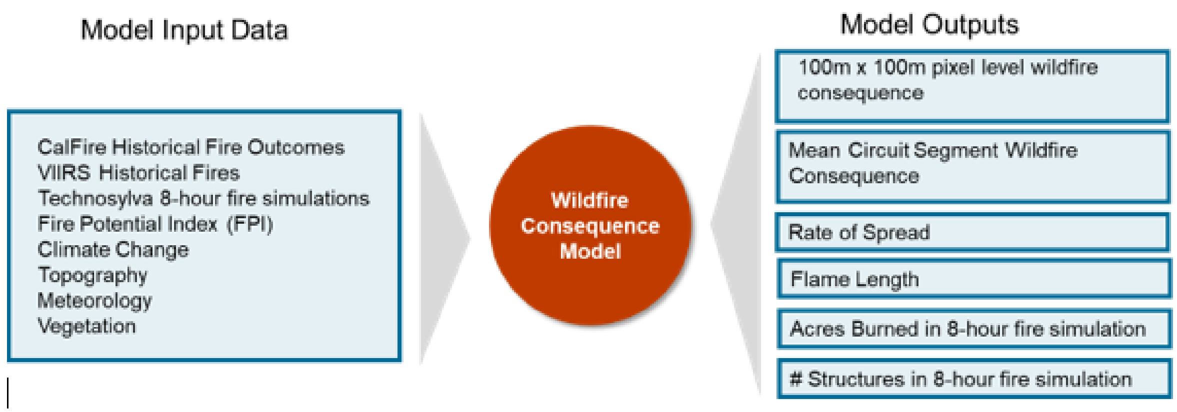
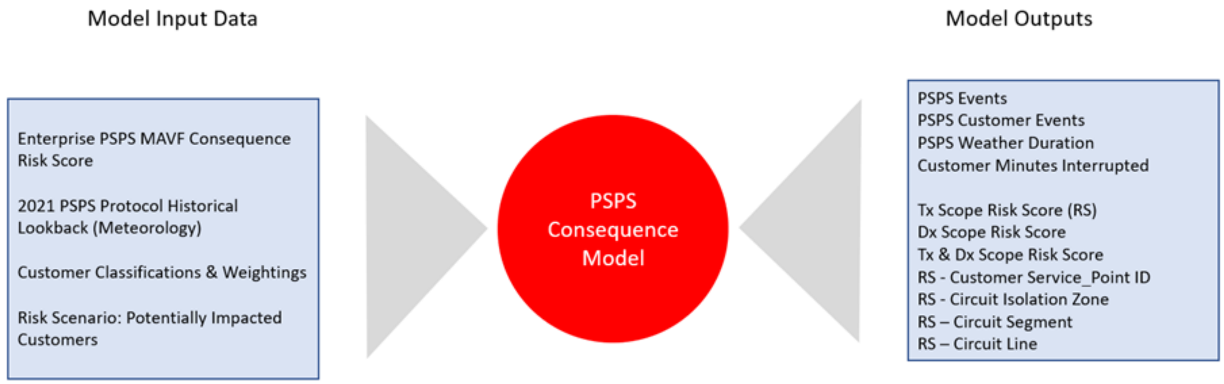
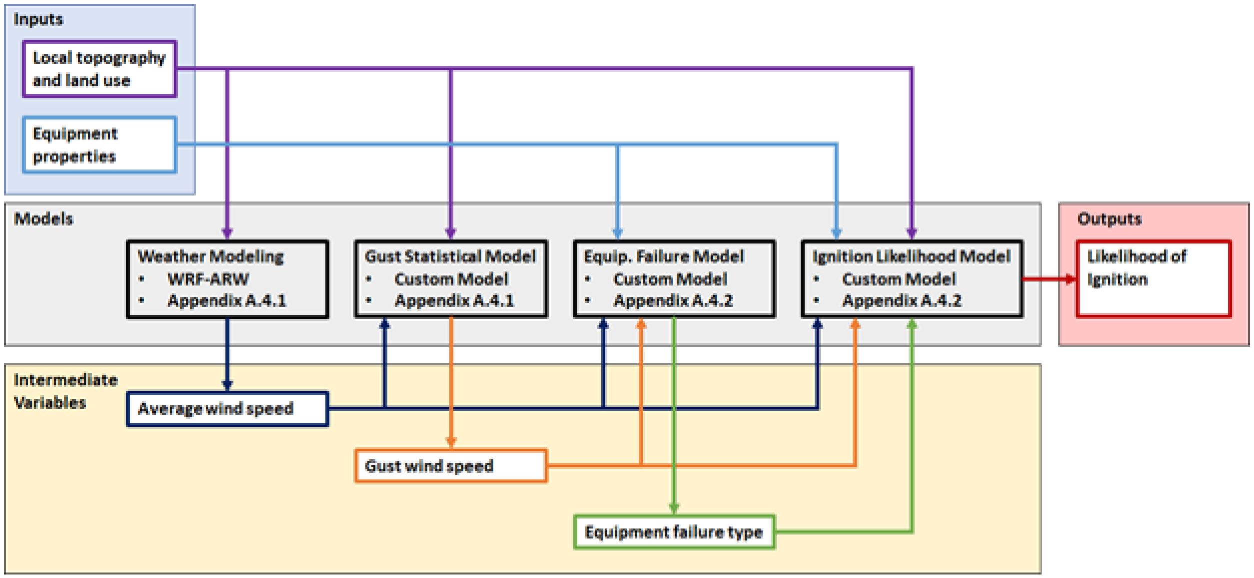


FIGURE PG&E-B-3:
PSPS CONSEQUENCE MODEL BOW-TIE



Appendix B.3 – High-Level Calculation Procedure Schematic

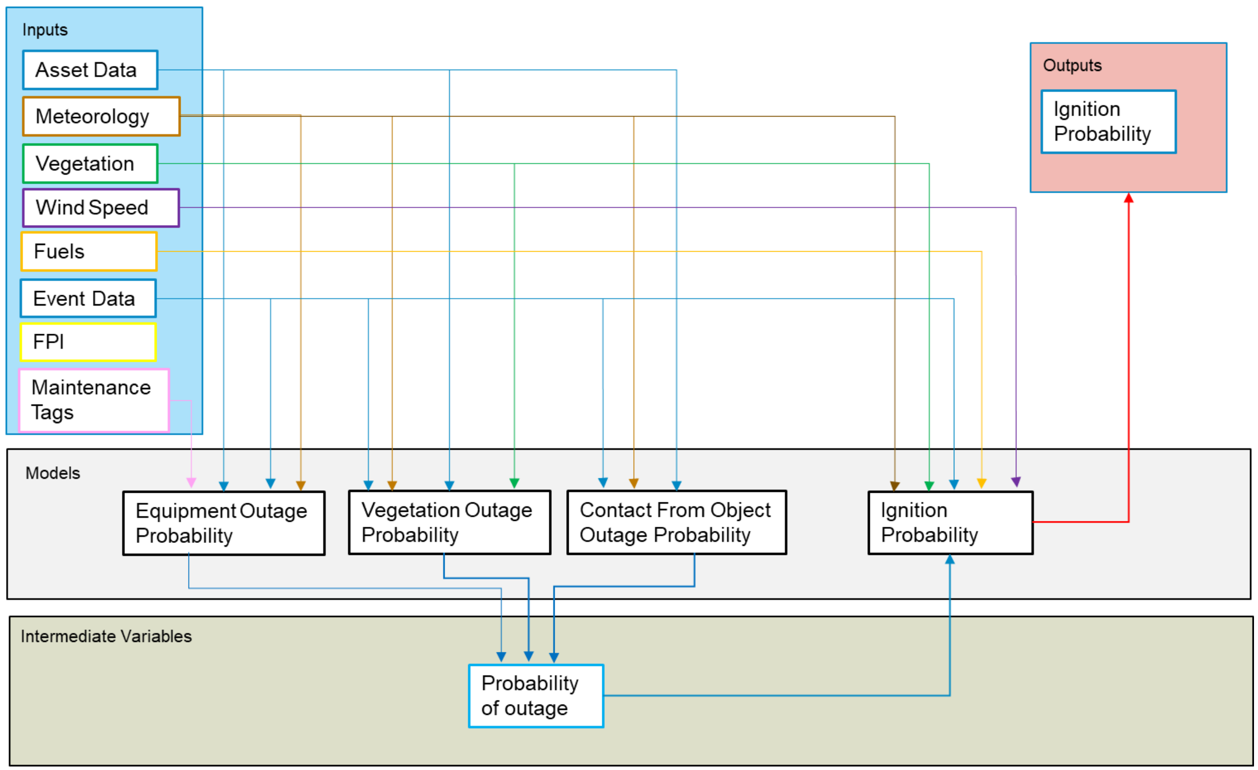
**FIGURE PG&E-B-4:
EXAMPLE CALCULATION SCHEMATIC**



Appendix B.3.1 – Ignition Probability Calculation Procedure Schematic

A more detailed set of diagrams and supportive narrative is provided in Section 6.2.2.1.

FIGURE PG&E-B-5:
IGNITION PROBABILITY CALCULATION PROCEDURE SCHEMATIC



Appendix B.3.2 – Wildfire Consequence Calculation Procedure Schematics

A more detailed set of diagrams and supportive narrative is provided in Section 6.2.2.2.

**FIGURE PG&E-B-6:
WILDFIRE CONSEQUENCE CALCULATION PROCEDURE SCHEMATIC**

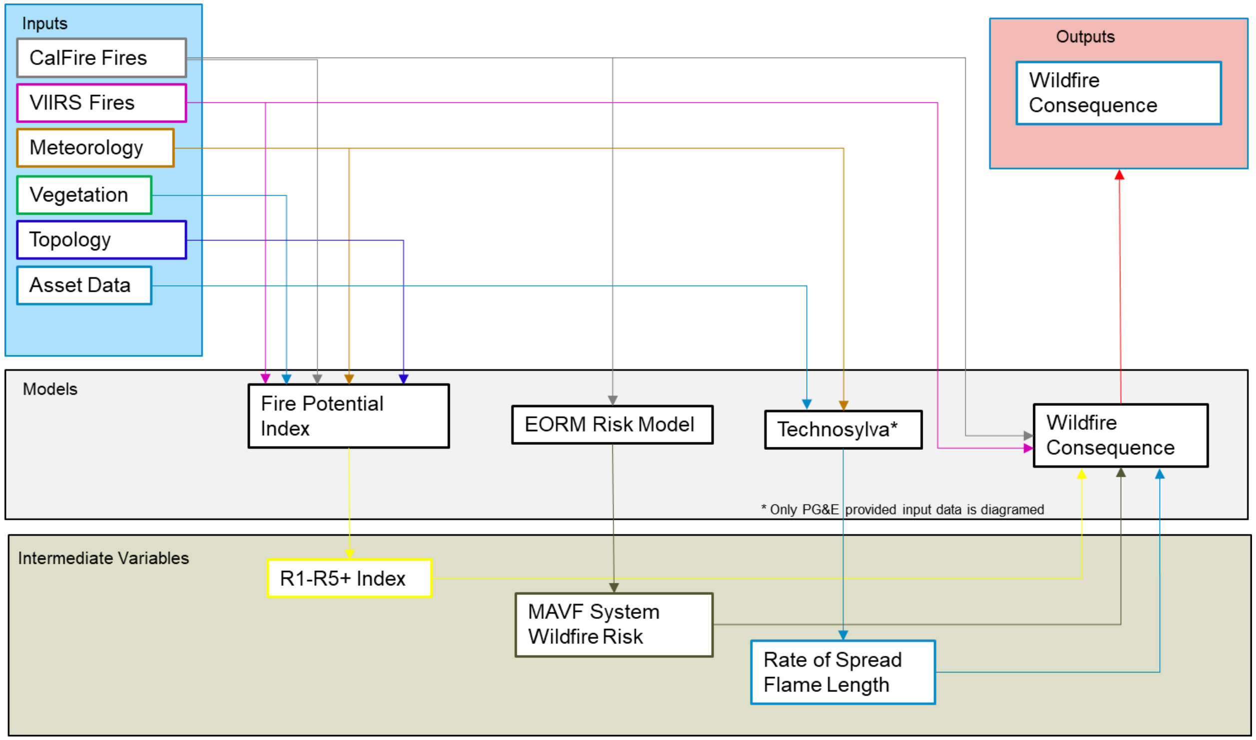
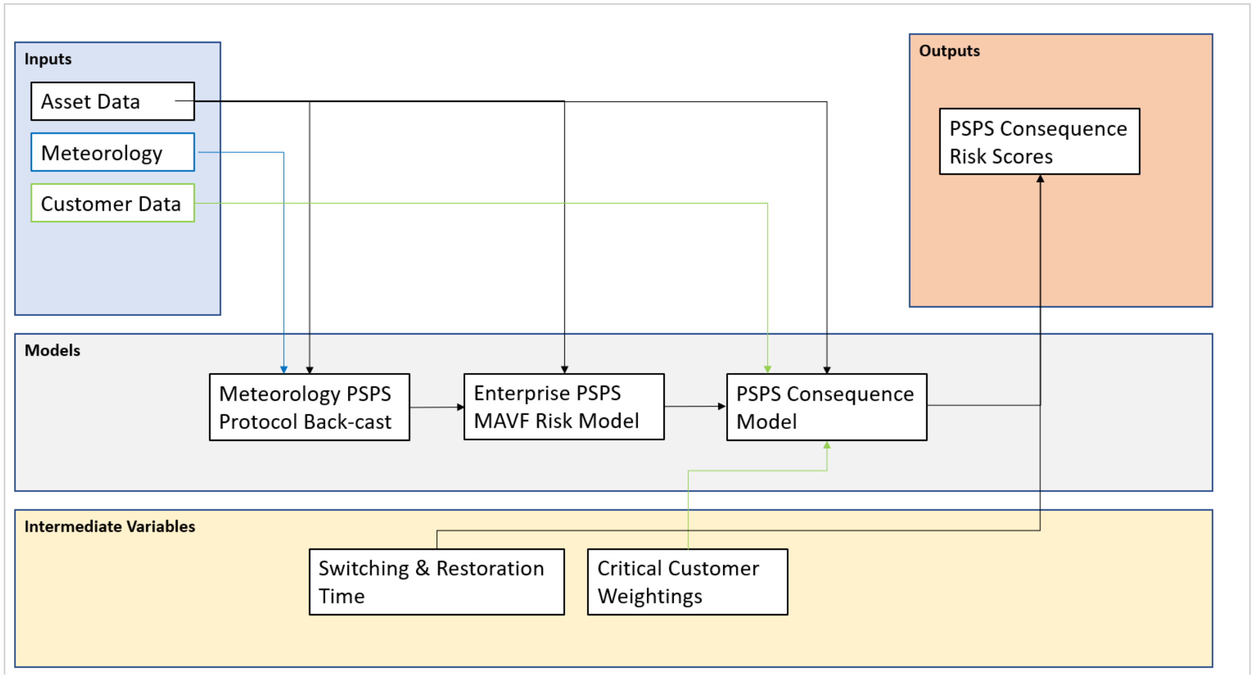


FIGURE PG&E-B-7:
PSPS CALCULATION SCHEMATIC



Appendix B.4 – High-Level Narrative Describing the Calculation Procedure

<u>Wildfire Distribution Risk Model and Wildfire Transmission Risk Model</u>

Model Purpose:

The Wildfire Distribution Risk Model (WTRM) and Wildfire Transmission Risk Model (WDRM) quantify the risk of wildfire ignited by the overhead transmission or distribution grid to support wildfire mitigation planning and prioritization. They assess expected wildfire risk over annual and multi-year timescales, given the conditions and assets associated with past grid events, including outages, PSPS, damage, hazards, and ignitions, from 2015-2021. To support the development of work plans around specific categories of mitigations and allow model structures to reflect what is known about specific failure modes, sub-models are trained on well-defined non-overlapping categories of grid events—subsets of all events defined by shared cause, sub-cause, and assets involved. Sub-models are tuned to the asset and environmental attributes expected and empirically confirmed to best predict grid events within each subset. Subset-level estimates of outage and ignition probability are multiplied by wildfire consequence (WFC) values derived from simulated location/fuels/conditions-specific wildfire outcomes calibrated to the satellite record of historical wildfires in California to produce asset- and location-specific risk estimates. The resulting risk values can be aggregated across subsets to produce “composite risk” estimates that span specific groups of (or all) subsets, capturing total risk while providing planners the ability to drill into contributing causes and the assets involved. These results are available to planners via interactive maps that overlay grid asset data or via roll-up to circuit segments, the planning units of system hardening, defined as the segments of grid infrastructure protected by the same protective device.

Assumptions and Limitations:

The predictive models used in the causal chain representing wildfire risk outlined in the Risk Model Framework contain inherent limitations due to modeling assumptions and data fidelity.

Predictive models, whether statistical or deterministic, such as the WDRM and WTRM, are limited in their ability to predict future conditions. Catastrophic wildfire, as a climate driven risk, is by its nature, dynamic and non-linear. While predictive models are not always right about future conditions, they are useful in directing where mitigation work should be applied. A prioritized list of grid locations generated from a risk model represent a current set of future potential destructive fire origins. As the models are refreshed each year, with the ignition and failure data from the most recent year, the dynamic nature of this climate driven risk will likely bring forward some previously lower ranked locations and drop back some previously higher ranked locations. What is certain is that by tracking these changes through the risk models, wildfire risk can be reduced and statistically run to the point where our company stand that catastrophic wildfire will cease will be realized.

For both the WTRM and WDRM the modeling approaches are based on mathematical and statistical modeling of physical systems limited to collection and processing of descriptions of the relative physical health of overhead transmission line assets. Whether it be asset data, event data, or environmental data, the data sets are representations that may not fully capture the ground truth that will be experienced in the future. For this reason, the model development schedule outlined below, includes efforts to continuously improve data sources such as electric grid asset data.

A specific assumption in the current causal chain modeled with the Wildfire Risk Framework is that all faults resulting from a failure contain the same energy. While the input data to the ignition probability given an outage model might correlate locations that might tend to have the potential for higher energy faults, this is not explicitly modeled. Ignitions can be predicted using raw outage probabilities but improved by passing outage probabilities through a probability of ignition given an outage model. This is because the probability of ignition given an outage model can account for subset-specific character of outages (i.e., more or less likely to cause a wire down or to occur during fire weather) and locations that experience more ignition conducive to wind, vegetation types, and fuel moisture. As with all aspects of PG&E's Wildfire Risk Modeling this is an area for future improvement and industry collaboration.

Calculation Procedure:

The WDRM and WTRM define risk as the product of the Likelihood of Risk Event (LoRE) and Consequence of Risk Event (CoRE). More precisely, the LoRE is the expected count of ignitions derived from the probability of an ignition of a given cause and sub-cause involving specific asset types and the CoRE is the expected consequence of an ignition, quantified by calibrated simulations. Risk can be calculated for specific subsets of grid event or aggregated across all subsets.

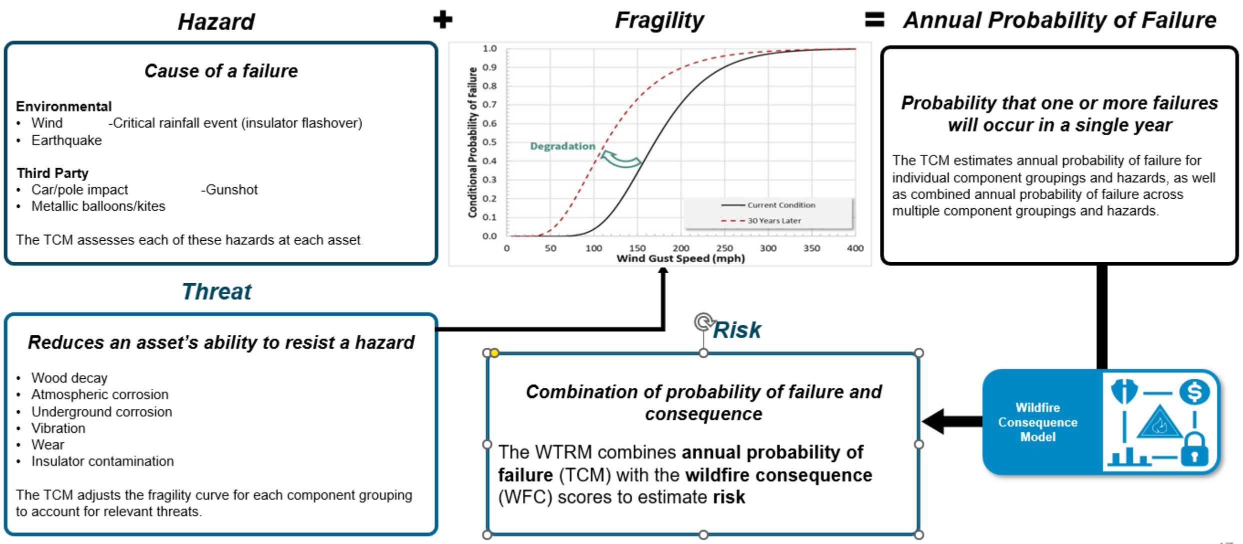
As described in Section 6.2 the WTRM and WDRM employ different approaches to calculating the LoRE portion outlined in the Risk Framework. The WDRM provides a set of predictive sub-models for categories of grid events, including third party, animal, support structures, transformers, vegetation caused, and equipment failure for several types of equipment and unifies these models into a single framework and set of results—via the sub-models and compositing described in Section 6.2.2.1.

To maximize the information produced by the WDRM and the training data available to sub-models, the WDRM first trains on and predicts failures capable of producing ignitions (e.g., outages) and then estimates the probability of an ignition arising from the same cause as the failures in question. This later step is based on the ignitions subset categories of cause, sub-cause and asset type(s) and local environmental conditions, including vegetation types, fuel dryness, and wind.

As failure events are less frequent on the transmission system, a machine learning approach is not preferred. As such, the WTRM approaches modeling from an engineering basis modeling the asset health (in the form of a fragility function) and the likelihood of experiencing an extreme external load (in the form of a hazard curve). The likelihood of a failure for a given asset can be evaluated by integration of the fragility and hazard curves. As assets degrade over time and conditions fragility curves can be adjusted to account for this degradation. The underlying causes of the degradation mechanisms are referred to as threats. Threats could include fungal decay for wood poles, or atmospheric corrosion for steel components. The degradation mechanisms associated with these threats are modeled to predict future fragility functions and associated failure rates.

With this approach the probability of failure is calculated for each of the component groupings itemized in Section 6.2.2.1 as shown in Figure PG&E-B-8 below.

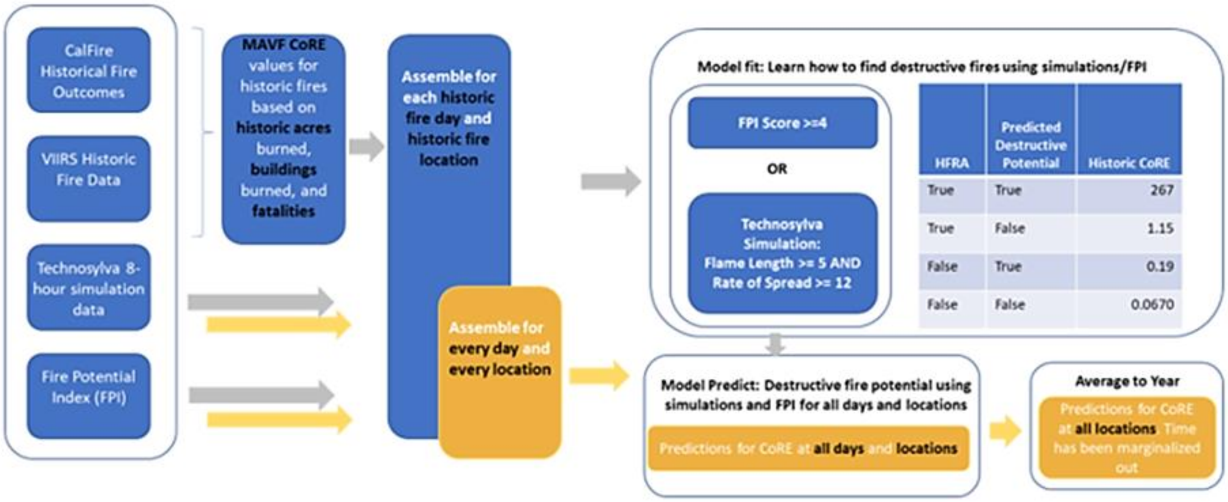
FIGURE PG&E-B-8:
OVERALL FRAMEWORK OF PG&E'S WILDFIRE TRANSMISSION RISK MODEL



The probabilistic outcomes for the Transmission and Distribution (T&D) systems are next combined with the spatial results of the WFC model to produce the Wildfire Risk values referred to as the WTRM and WDRM respectively. The Wildfire Consequence calculations calibrate wildfire simulation outputs against historical outcome data on California wildfires from satellite observations and fire agency records. As described in more detail in Section 6.2.2.2, input data is prepared from both historical and simulated results to represent a set of outcomes for every day/location along electric T&D assets. This day/location set of data is then evaluated to determine whether the represented fire consequences are consistent with the average Multi-Attribute Value Function (MAVF) CoRE value assigned to historical destructive fires. The historical data is used to identify thresholds for the Fire Potential Index (FPI) and Technosylva models across each time and location. These thresholds establish the classifier conditions that indicate (predicts) that there may be a potentially destructive fire. Conversely, non-destructive potential is predicted when the classifier conditions are not met. Each of the predicted destructive/non-destructive outcomes has an associated mean MAVF CoRE consequence from the observed, historic outcomes. Predicted destructive potential/non-destructive potential are computed both inside and outside the HFRA to complete this partition of the day/location data.

This process is shown in more detail in Figure PG&E-B-9 CoRE Process Steps. The next step is to use the classifier described above and the starting locations of historical fires, to determine the mean MAVF for a matrix of HFRA designation and the destructive potential prediction for each historical fire location.

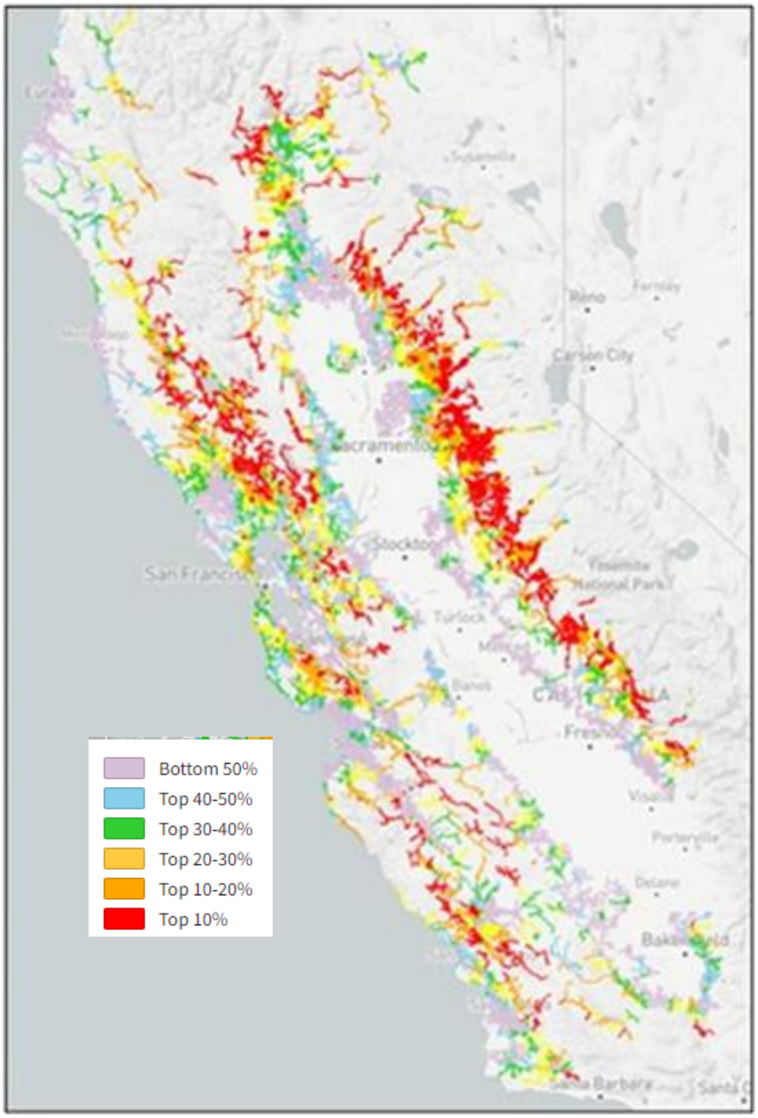
FIGURE PG&E-B-9:
CoRE PROCESS STEPS



<u>Assigning Grid Pixel CoRE Values From the "Destructive Potential" Classification</u>

To project CoRE values, the covariates are computed for as many pixels as possible. For each day in the fire season, the FPI R-score and Technosylva simulation results are classified for each pixeled location. From the pixel destructive potential classification, the appropriate CoRE value is assigned from the WFC. The final CoRE value for each pixel is the aggregate of the daily CoRE values.

FIGURE PG&E-B-10:
WILDFIRE CONSEQUENCE PIXEL MAP



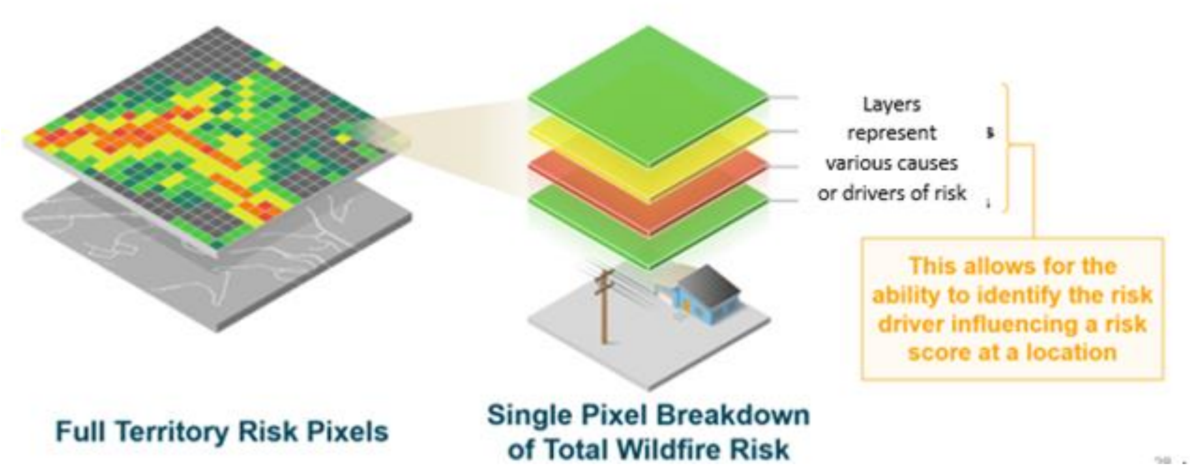
Presentation and Characterization of model results for use in developing mitigation workplans:

The primary purpose for the wildfire risk models is to inform various PG&E wildfire risk mitigation plans, also known as Work Plans. Work plans are produced, then executed, by various programs, including:

- <u>System Hardening</u>: Replaces existing assets with more resilient versions (e.g., stronger poles and wires) or moves assets to lower-risk locations (e.g., underground, different routes, etc.);
- <u>Pole Replacement</u>: Replaces old and worn wood distribution poles; and
- <u>Other Inspection and Repair Programs</u>: Typically focused on finding and quickly fixing various overhead distribution asset issues.

The output of the WTRM and WDRM is made available in tabular form as well as a spatial map with several layers—each characterizing risk from different causes or assets. These layers of risk can be examined and compared individually, or they can be composited together to understand the full risk from overhead distribution lines at a particular location or asset.

FIGURE PG&E-B-11:
COMPOSITING OF RISK OVERVIEW



Note that the risk varies across the geographic area depending on the characteristics of the environment, the weather, the vegetation, and the assets themselves.

Model Development Schedule:

PG&E will produce annual updates to the WDRM and WTRM. As part of our continuous improvement plan, the next WDRM, WDRM version 4, is planned for finalization during Q1 of 2023. For this update planned improvements include consequence values that account for difficulty of suppression, and factors that influence the effectiveness of evacuation in advance of fires. The model will continue to account for PSPS hazards and damages as proxies for grid events that would have occurred with the power on and will add the ability to account for the effects on EPSS (protective device settings that make them more likely to trigger protective outages under fire conditions).

Another area of focus is allowing for algorithmic specification of the circumstances under which specified mitigations are applicable, leading to a more precise application of mitigation effectiveness factors only to the degree to which they can be achieved—for example, the use of less combustible transformer fluids will be applicable only to transformers that lack them. Finally, the WDRM v4 will be based on 2022 updates to event, asset, weather, and vegetation/fuels data and will benefit from ongoing efforts to test out and incorporate new or improved model structures and covariates to improve model predictive performance.

FIGURE PG&E-B-12:
RISK MODEL DEVELOPMENT SCHEDULE

MODEL	2023	2024	2025
WILDFIRE DISTRIBUTION RISK MODEL (WDRM)	$P_{(out)}$ & PIO for Dx Grid Automated Code Base Mitigations Model Entire Dx Grid Asset Data Improvements	Animal / Bird 3rd Party Switches Shunt Caps Vegetation Mortality Model Causality with workplans All data in dB defined & explained Location Specific Mitigations Asset Data Improvements	Unknown Lightening Seismic Risk Mitigation Automation Reporting Risk Reduction Evaluation Model Performance with Actuals Asset Data Improvements
CONSEQUENCE MODELS	WFC all Burnable	Egress Suppression Public Safety Reliability Statistical WFC Output	Vulnerable Communities Long Term Health Effects Population Growth in WUI
WILDFIRE TRANSMISSIONRISK MODEL (WTRM)	Wind 11 Fragility Threats 3rd Party Seismic	Asset Data Improvements Vegetation Insulator Mechanical Wear Conductor Mechanical Loading Animal / Bird All data in dB defined & explained Location Specific Mitigations	Asset Data Improvements Unknown Lightning Risk Mitigation Automation Reporting Risk Reduction Evaluate Model Performance with Actuals

PSPS Consequence Model

Purpose of the Calculation/Model:

The purpose of the calculation/model is to encompass the additional risk created by Public Safety Power Shutoffs into the overall total overall utility risk. This allows an understanding of relationship between the wildfire risk and PSPS at each location or granularity.

The assumption and limitations are largely impacted by any changes in the PSPS protocols and the need to re-assess the level of impact against historical events. Because the system configuration is constantly changing, the accuracy of historical backcasts is not perfect.

Outputs of this model are generally represented in a tabular format with a ranking of highest to lowest locations (various levels of granularity based on need) to drive risk prioritization, especially around PSPS mitigation work-planning.

Over the triennial WMP cycle, the PSPS model will evolve to account for any changes in PSPS protocols, and the changes due to community vulnerability assessment inclusion.

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APPENDIX C

ADDITIONAL MAPS

Appendix C – Additional Maps

In this appendix, the electrical corporation must provide the additional maps required by the Guidelines. As stated in the General Directions, if any additional maps needed for clarity (e.g., the scale is insufficiently large to show useful detail), the electrical corporation must either provide those additional maps in this appendix or host applicable geospatial layers on a publicly accessible web viewer. If the electrical corporation chooses the latter option, it must refer to the specific web address in appropriate places throughout its Wildfire Mitigation Plan (WMP). Additionally, the electrical corporation must host these layers until the submission of its 2026-2028 WMP or until otherwise directed by Office of Energy Infrastructure Safety (OEIS or Energy Safety). The electrical corporation may not modify these publicly available layers without cause or without notifying Energy Safety.

We have included a collection of geospatial datasets that have been stored in an ESRI file geodatabase (FGDB). They provide visual representation of and attributes for the data that are discussed in the Wildfire Mitigation Plan. File geodatabases are advantageous as they also allow for large volumes of data to be shared/consumed, enable advanced spatial analytic capabilities, and are an industry standard.

Table PG&E-C-1 below includes a list of applicable layers that are represented in our FGDB file (Attachment 2023-03-27_PGE_2023_WMP_R1_Appendix C _Atch01). Access to the FGDB file requires software designed to read and interact with these file types. These software platforms allow users to open and view the datasets.

Examples of free and publicly available software options that enable access to the file geodatabases are provided below:

- Software Option 1: https://www.arcgis.com/index.html;
- Software Option 2: https://qgis.org/en/site/;
- Software Option 3: https://saga-gis.sourceforge.io/en/index.html; and
- Software Option 4: https://www.bluemarblegeo.com/global-mapper/.

TABLE PG&E-C-1:
LIST OF GEOSPATIAL DATASETS

Attachment Subfolder	File Name	Reference
Group 5	5.1 Service Territory	Figure PG&E-5.1-1: Population Density Map of Highly Rural, Rural, and Urban Customers.
Group 5	5.3.2 Catastrophic Wildfire History	Figure 5.3.2-1: Utility-Related Catastrophic Wildfires within PG&E's Service Territory Map.
Group 5	5.3.3 High Fire Threat Districts	Figure PG&E-5.3.3-1: HFTD Tier 2 and Tier 3, and PG&E's HFRA, November 2022.
Group 5	5.3.5 Topography	Figure PG&E-5.3.5-1: Topographic Map of PG&E Service Territory and Adjacent Portions of California with Geomorphic Province Boundaries.
Group 5	5.4.1 Urban, Rural and Highly Rural Customers	See Section 5.1.
Group 5	5.4.2 Wildland-Urban Interfaces (WUI)	Figure PG&E-5.4.2-1: Population Density Map of WUI.
Group 5	5.4.3.1 Individuals at Risk of Wildfire	Figure PG&E-5.4.3-1: 2020 Census Population.
Group 5	5.4.3.2 Social Vulnerability and Exposure to Electrical Corporation Wildfire Risk	Figure PG&E-5.4.3-2: Exposure and Social Vulnerability Map.
Group 5	5.4.3.3 Sub-Divisions with Limited Egress or No Secondary Egress	See Section 5.4.3.3; Unable to include a figure for this Section.
Group 5	5.4.4 Critical Facilities and Infrastructure	Figure PG&E-5.4.4-1: Critical Facilities Count by County.
Group 6	6.4.1.1 Geospatial Maps of Top-Risk Areas within HFRA	Figure PG&E-6.4.1-1: WDRM Outputs Map. Figure PG&E-6.4.1-2: WTRM Outputs Map. Figure PG&E-6.4.1-3: PSPS Risk Map.
Group 6	6.4.1.2 Proposed Updates to the HFTD	Attachment 2023-03-27_PGE_2023_WMP_R1_Appendix C _Atch01.
Group 9	9.1.2 Identification of Frequently De-energized Circuits	Figure PG&E-9.1.2-1: De-Energized Circuits by Frequency with HFTD Contour Overlays.

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APPENDIX D

AREAS FOR CONTINUED IMPROVEMENT

Appendix D – Areas for Continued Improvement

ACI PG&E-22-01 – Prioritized List of Wildfire Risks and Drivers

Description:

Currently, Pacific Gas and Electric Company's (PG&E or the Company) prioritized list of wildfire risks and drivers (Table 4.2-2) weights the risk drivers by average outage multiplied by ignition rate; it does not account for the likelihood of the ignition to cause a catastrophic wildfire.

Required Progress:

In its 2023 Wildfire Mitigation Plan (WMP), PG&E must further refine its prioritized list of wildfire risks and drivers. It must do so by weighting each risk driver by likelihood of causing a catastrophic wildfire (e.g., does this ignition tend to happen in high wildfire risk areas identified by PG&E's risk models, including the High Fire Threat District (HFTD)).

PG&E Response:

Office of Energy Infrastructure Safety (OEIS or Energy Safety) has updated the definition of catastrophic wildfire in the 2023-2025 WMP Technical Guidelines to a fire that caused at least one death, damaged over 500 structures, or burned over 5,000 acres. As such, PG&E is in the process of updating our enterprise risk framework to match the new definition as visualized by a risk bowtie.

Figure PG&E-22-01-1 below is a risk bowtie, in this case overall wildfire risk, which shows how PG&E maps each risk driver to its associated consequence outcome. We describe this process in Section 7.1.4.2.

Historically, PG&E has partitioned the consequence outcome categories by the combination of Red Flag Warning (RFW) and Small/Large/Destructive/Catastrophic Fires. In this case, catastrophic represents a Destructive Fire that results in a serious injury or fatality involved, which is from the definition that has been further clarified by the Energy Safety. We will be updating our consequence outcomes to align with the revised definition in future modeling iterations.

FIGURE PG&E-22-01-1:
WILDFIRE RISK BOWTIE MAPPING RISK DRIVERS TO CONSEQUENCE OUTCOMES

In an initial assessment, using the existing pre-mitigation wildfire baseline bow-tie analysis results and an analysis of the historical fires data, PG&E estimated the likelihood of a catastrophic wildfire by risk driver, based on the new Energy Safety definition of catastrophic risk, as shown in Table PG&E-22-01-1.

TABLE PG&E-22-01-1:
WILDFIRE RISK DRIVERS

	Pre-Mitigation Frequency of Catastrophic Wildfire			% Pre-Mitigation Frequency of Catastrophic Wildfire		
	HFTD	Non-HFTD	All	HFTD	Non-HFTD	All
1. Vegetation Contact	1.3	0.1	1.3	56%	21%	52%
2. Equipment/facility failure	0.7	0.1	0.8	33%	43%	34%
3. Contact from object	0.1	0.1	0.2	6%	31%	9%
4. Wire-to-wire contact	0.05	0.00	0.05	2%	0%	2%
5. Unknown	0.03	0.01	0.04	1%	3%	2%
6. Other	0.02	0.00	0.02	1%	1%	1%
7. Utility work/Operation	0.004	0.0001	0.004	0%	0%	0%
8. Vandalism/Theft	0.002	0.002	0.004	0%	1%	0%
9. Contamination	0.002	0.001	0.004	0%	1%	0%
Total	2.2	0.3	2.5	100%	100%	100%

Note: Based on Energy Safety's updated definition, the analysis assumed that: 100 percent chance that Destructive Fires would be Catastrophic Wildfires in the HFTD; 50 percent chance that Destructive Fires would be Catastrophic Wildfires in Non HFTD; 28 percent chance that Large Fires would be Catastrophic Wildfires in the HFTD; and 16 percent chance that Large Fires would be Catastrophic Wildfires in Non HFTD. The "Catastrophic Wildfires" designation is based on Energy Safety's 2023 WMP guidance while the "Destructive/Large Fires" designation is PG&E's definition from our bow tie.

ACI PG&E-22-02 – Collaboration and Research in Best Practices in Integrating Climate Change Impacts and Wildfire Risk and Consequence Modeling

Description:

PG&E and the other large utilities are currently pursuing their own efforts at integrating the potential impacts of climate change on their risk and consequence modeling on the topic of integrating climate change into projections of wildfire risk. They are not actively collaborating with each other on these efforts and are not actively taking advantage of the existing climate change modeling expertise of state agencies and academic institutions.

Required Progress:

Prior to the submission of their 2023 WMPs, all electrical corporations (not including independent transmission operators) must participate in an Energy Safety-led scoping meeting to discuss how utilities can best learn from each other, external agencies, and outside experts. They must also participate in any follow-on activities to this meeting. In addition, the climate change and risk modeling scoping meeting will identify future topics to explore regarding climate change modeling and impacts relating to wildfire risk. This scoping meeting may result in additional meetings or workshops or the formation a working group. Energy Safety will provide additional details on the specifics of this scoping meeting in due course.

PG&E Response:

PG&E looks forward to participating in an Energy Safety-led scoping meeting regarding climate change and wildfire risk research and collaboration.

PG&E is currently participating in the ongoing Energy Safety-led Risk Model Working Group (RMWG) sessions. In September 2022, we participated in a technical work group with other California utilities where participants discussed the approaches each utility is taking to determine and model on-going and worsening climate change impacts to our service territory.

We are also participating in several other activities related to addressing climate change risk including:

- We facilitated ongoing joint utility collaboration as part of the 2018-2020 California Public Utilities Commission (CPUC or Commission) Rulemaking to Consider Strategies and Guidance for Climate Change Adaptation;
- We are participating in monthly calls with Southern California Edison Company (SCE) related to our climate vulnerability assessment and integrating climate change risk in enterprise risk assessment and planning;
- Along with SCE, we are a leading member of the Electric Power Research Institute's Climate READi (Resilience and Adaptation initiative), a multi-year initiative that will produce "one of the most comprehensive, integrated approaches to physical climate risk assessment;"

- We participate in the Institute of Electrical and Electronics Engineers Distribution Resilience Working Group that is focused on creating metrics and mitigations for climate risk to electric distribution facilities; and
- We are an active participant in multiple CPUC proceedings dealing with climate risk, the value of resilience, and integrating long-term and near-term risks including wildfire risk.

ACI PG&E-22-03 – Inclusion of Community Vulnerability in Consequence Modeling

Description:

PG&E does not currently adequately include the impacts of wildfire on communities, such as community vulnerability, within consequence modeling.

Required Progress:

Prior to the submission of their 2023 WMPs, all electrical corporations (not including independent transmission operators) must participate in an Energy Safety-led scoping meeting to discuss how to best learn from each other, external agencies and outside experts on the topic of community vulnerability. They must also participate in any follow-on activities to this meeting. In addition, the community vulnerability scoping meeting will identify future topics to explore regarding integration of community vulnerability into consequence modeling and impacts relating to wildfire risk. This scoping meeting may result in an additional meetings or workshops or the formation of a working group. Energy Safety will provide additional details on the specifics of this scoping meeting in due course.

PG&E Response:

PG&E participated in an Energy Safety-led scoping meeting on December 8, 2022 focusing on Community Vulnerability and in the first Risk Model Work Group meeting held on December 14, 2022. We will participate in follow-up activities as well. We expect to work with stakeholders to learn more about community vulnerability, and we are working to integrate community vulnerability into both our Wildfire and our Public Safety Power Shutoff (PSPS) consequence modeling. This includes critical facilities and infrastructure, as well as customers enrolled in the medical baseline allowance program or who have durable medical equipment or access needs.

The recent Commission Phase II Decision Adopting Modification to the Risk-Based Decision-Making Framework and Directing Environmental and Social Justice (ESJ) Pilots[190] (Phase II Risk Assessment and Mitigation Phase (RAMP) and ESJ Pilots Decision) means that PG&E will be the first California Investor-Owned Utility (IOU) to file the results of the ESJ Pilot Study in our 2024 RAMP Application.

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[190] D.22-12-027.

ACI PG&E-22-04 – Fire Suppression Considerations

Description:

PG&E's fire spread modeling does not currently factor in suppression effects (e.g., fire department efforts).

Required Progress:

Prior to the submission of its 2023 WMP, PG&E must work with other utilities to evaluate how to best account for, quantify, and model suppression effects on wildfire spread. Further guidance will be determined and covered during the risk model working group meetings established by Energy Safety's 2021 WMP Action Statements.

PG&E Response:

Meetings continue to take place between PG&E, SCE, and San Diego Gas & Electric Company (SDG&E) to evaluate how to best account for, quantify, and model suppression effects on wildfire spread. As part of this collaborative effort, the three utilities have been leveraging fire simulation data from Technosylva, specifically their Terrain Difficulty Index. As a result of this collaborative work, we developed an approach to model suppression as part of our 2022 WMP Commitment A.05. We continue to collaborate with the other utilities in preparation for a future Energy Safety-led working group meeting on the topic of fire suppression considerations.

ACI PG&E-22-05 – 8-Hour Fire Spread Simulations

Description:

PG&E's 8-hour fire spread simulations may be impacting the accuracy of its wildfire spread consequence modeling.

Required Progress:

PG&E must:

- *Prior to the submission of its 2023 WMP, PG&E must benchmark against other utilities to account for catastrophic fire risk that occurs more than eight hours post-ignition and provide a summary of lessons learned in its 2023 WMP;*
- *Further guidance may be determined and covered within the risk model working group established by the 2021 WMP Action Statements; and*
- *In its 2023 WMP, PG&E must include a description of resulting changes to its wildfire spread consequence modeling or anticipated changes and a timeline for implementation.*

PG&E Response:

PG&E, along with other IOUs, use Technosylva's Wildfire Risk Reduction Model (WRRM) for infrastructure and mitigation planning activities. The WRRM application uses a standard 8-hour duration for all fire spread simulations conducted using historical data (climatology). This duration represents a typical first burning period of a fire, consistent with response and suppression efforts. Previous research and historical data analysis have determined that approximately 90 percent of large destructive fires can be identified by their behavior in the first burning period alone and do not require longer simulations to identify these scenarios. However, from collaborative benchmarking among PG&E, SCE, and SDG&E, and subsequent consultation with Technosylva, we asked Technosylva to conduct a sensitivity study on 24-hour wildfire consequence simulations.

Technosylva has conducted an initial sensitivity study and presented results to the utilities individually. The preliminary results comparing the 8-hour and 24-hour simulations for a portion of PG&E's service territory demonstrated that the longer simulations present a wider range of potential outcomes along with an extended extent of impact. Specifically, locations with fast moving grassy fuels could slow when reaching residential or less burnable territory and some locations with less combustible fuels can reach locations with higher combustible fuels resulting in higher consequences. In general, 24-hour simulations result in higher impacts as simulated fires are more likely to reach highly populated areas despite decreasing reliability on the weather forecasts as time progresses, and unknown suppression effectiveness over time. Sensitivity analysis is continuing, and PG&E will be able to provide results in 2023 that quantify the effectiveness of shorter versus longer simulation durations.

PG&E will continue to collaboratively work with Technosylva and the other utilities to appropriately incorporate these longer simulations into future wildfire risk models.

ACI PG&E-22-06 – Addressing Increase in Risk Events

Description:

PG&E reports an increase in risk events from 2021 to 2022.

Required Progress:

In its 2023 WMP, PG&E must:

- *Analyze root causes and trends for the increases in risk events and ignition likelihood broken down by sub-driver;*
- *Provide its plans to address increases in ignition rates broken down by risk drivers and sub-drivers, including efforts to address the root cause(s) outside of routine or program-level WMP initiatives; and*
- *Describe and quantify effectiveness for how PG&E anticipates Covered Conductor (CC) and undergrounding initiatives will impact expected ignitions due to conductor damage or failure.*

PG&E Response:

PG&E has not observed an increase in risk events and ignition likelihood in our territory in 2022 following our full HFTD deployment of Enhanced Powerline Safety Settings (EPSS). Specifically, PG&E has observed a tangible reduction of risk events and ignition likelihood across the two most-frequent cause drivers (vegetation contact and equipment failures). These two suspected initiating events are the riskiest in term of numerical count and are where we have the most amount of control to prevent the ignition. Table PG&E-22-06-1 below shows the CPUC-reportable fire ignitions in 2022 compared to the prior 3-year average.

TABLE PG&E-22-06-1:
CPUC-REPORTABLE FIRE IGNITIONS – COMPARING 2022 TO 3-YEAR AVERAGE (2019-2021)

2022 vs. 3-Year Average of Reportable Ignitions by Suspected Initiating Event		
Suspected Initiating Events	**3-Year Average**	**2022**
Contact from Object – Vegetation	63	38
Equipment Failure – PG&E	33	14
Contact from Object – Animal/Bird	12	7
Wire-to-Wire Contact	3	0
Unknown/Other (inc. Weather)	4	1
Contamination	3	2
Contact from Object – Third Party	16	19
Utility Work/Operation	1	6
Total	134	87

Table PG&E-22-06-1 shows a reduction in the number of CPUC-reportable ignitions overall and for every driver except for third-party contacts and utility work/operation. The 2022 results for third-party contacts are higher than the mean, but within the normal variation year-over-year (e.g., PG&E observed 21 ignitions caused by third-party contact in 2021).

PG&E attributes the increase in Utility Work/Operation ignitions to improvements in our processes for identifying the cause of ignitions, through our Enhanced Ignition Analysis (EIA) Program, rather than an increases in occurrence. By better identifying the causes of ignitions we develop lessons learned and identify areas for improvement.

We expect both CC and undergrounding to be effective in reducing ignitions due to conductor contact damage or failure. With undergrounding, ignitions due to conductor contact damage or failure is 99 percent, or virtually, eliminated, as typical underground ignitions are not caused by the conductor itself, but due to limited incidents from third-party contact around the subsurface or padmount facilities for an undergrounded circuit.

For CC, we expect fewer ignitions in areas where we replace bare conductor with CC. While CC is effective in reducing ignition risk from small vegetation, contact from object, and equipment failure, there are still circumstances, such as contact from large tree falls and vehicle strikes, that can damage lines where CC has been installed, and ignitions can occur. We discuss this issue in ACI PG&E-22-11.

ACI PG&E-22-07 – Applying Modeling Lessons – Learned from Third-Party Review

Description:

The third-party review of PG&E's third version of its risk model identified issues for PG&E to address.

Required Progress:

In its 2023 WMP, PG&E must provide its plan to address any issues identified in the 2022 third-party review of its risk model, including:

- *Specific steps and improvements PG&E plans to implement to address gaps;*
- *A timeline for implementation; and*
- *An update on progress made to address the issues, including references to where changes have been applied.*

PG&E Response:

E3 – Energy, Environment and Economics, an independent third party, conducted a review of PG&E's WDRM, version 3 (E3 Review of Model v3).[191] The objective of the review was to:

- Review the suitability and applications of consequence data in the modelling framework;
- Review the specific use of the Risk Model Information in each of its operations areas; and,
- Describe potential future uses of WDRM v3 and longer-term multi-year wildfire planning models.

The E3 Review of Model v3 concluded:

- PG&E has made substantial progress in transforming its model from one that was primarily used to validate mitigation measures chosen by its Subject Matter Experts (SME) within high fire zone areas to a model that can be used to supplement and prioritize the targeting of mitigation measures across its entire service territory.[192]
- The construct of [WDRM] v3 appears to be consistent with their [PG&E's] commitment in their [PG&E's] WMP to refocus mitigation work to achieve a target

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[191] E3 Review of PG&E's Wildfire Risk Model Version 3, dated May 2022. Please see Attachment 2023-03-27_PGE_2023_WMP_R0_Section 6.6.1_Atch01.

[192] *Id.* at p. 4.

where 80 percent of their work is focused on mitigating the risk of the highest 20 percent of identified line segments.[193]

- PG&E has made a substantial effort to incorporate feedback from the CPUC, stakeholders, E3 and its internal users to update the WDRM between versions 2 and 3. The updates made represent real improvements in several critical areas. From E3's review, the modeling team includes a group of highly skilled professionals from inside and outside of PG&E. The model is leveraging the best available data and methods to prioritize risk levels by geographic area and ignition type allowing for evidence-based decision-making. This model represents an improvement from v2. Most of modeling limitations are driven by limitations in data and resources which are difficult for the modeling team to directly solve.[194]

E3 identified areas for improvement in the WDRM v3.[195] We list these recommendations, as well as the 2022 progress-to-date and ongoing improvement plans in Table PG&E-22-07-1 below.

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193 *Id*. at p. 4.

194 *Id*. at p. 11.

195 *Id*. at p. 4.

**TABLE PG&E-22-07-1:
E3 IDENTIFIED AREAS FOR IMPROVEMENT**

Line No.	Recommendation	Progress	Next Steps
1	Standardizing and documenting the relationship between the model and SMEs	Developed and implemented standardized client process in development of WDRM v4 model.	Conduct ongoing updates to the process in alignment with WDRM v4 development enhancements.
2	Improving the transparency and validity of the consequence portion of the model	Collaboration with other utilities to improve wildfire consequence model resulting in expanding length of Technosylva simulations to 24-hours.	Aim to incorporate into WDRM v4 or v5.
3	Establishing a data quality control process	Developed asset data quality dashboards to prioritize asset data improvement projects.	Identify and execute asset data improvement projects.
4	Establishing an expanded roadmap for model direction	Developed for WDRM and Wildfire Transmission Risk Model (WTRM).	Continue to incorporate items from Energy Safety RMWG and SME feedback throughout model development cycles.
5	Exploring potential further use cases of the model	Expanded individual sub-models to improve alignment with workplans in WDRM v4.	Include expanded sub-models in WDRM v4.
6	Coordinating PG&E's process with broader State-wide wildfire planning	Communicated recommendations to Energy Safety as part of the proposed work on coordinating utility and state wildfire plans.	Risk Model Workgroup session in 2023.

E3 also evaluated PG&E's progress against recommendations made to improve the WRDM v2 model. E3 noted that PG&E has addressed many of these recommendations in the current WDRM v3 modeling but there are some remaining suggestions that PG&E plans to address or incorporate in version 4 of the wildfire risk model.[196] The three items E3 recommends PG&E continue to improve are listed on lines 1, 2, and 4 in Table PG&E 22-07-1 above.

196 *Id*. at p. 12.

ACI PG&E-22-08 – Better Application of Specific Lessons Learned From Utility-Caused Fires

Description:

PG&E reports lessons from individual catastrophic fires. However, the lessons learned as reported provide insufficient detail about how they are tied to the specific cause of each fire. Furthermore, PG&E does not provide sufficient details on measures implemented as a result of these lessons, which may differ by fire.

Required Progress:

In its 2023 WMP, PG&E must provide specific analysis on how lessons learned are specifically tied to the causes of past PG&E-equipment related catastrophic fires beyond what it has provided to date. This must include:

- *Specific cause analysis for each catastrophic fire that analyzes in detail the underlying sources and issues that led to ignition and spread;*
- *Evaluation of underlying programmatic and systemic issues in relation to the causes; and*
- *Consideration of resource availability to make sweeping changes, including analysis of risk prioritization and cost/benefit analysis compared to other wildfire mitigation changes being made.*

PG&E Response:

As part of our 2022 Revised WMP, we provided a description of each catastrophic wildfire that: (1) occurred since 2017; (2) was greater than 500 acres; and (3) was determined by the California Department of Forestry and Fire Protection (CAL FIRE), a local fire suppression agency, the Safety and Enforcement Division (SED), or the United States Forest Service (USFS) to have been caused by PG&E or its assets. For each fire, we described the lessons learned, measures to mitigate the cause, and how the lessons learned have been integrated into our wildfire strategy in addition to the cause and date of ignition. The information was based on information available to PG&E at that time and evaluations and/or reports or information provided by external parties. We noted that we are continuing to evolve and strengthen our mitigations based on ongoing learnings especially with our EIA Program.

As part of the approval of PG&E's 2022 Revised WMP, Energy Safety asked for more analysis on how lessons learned are tied to the causes of past PG&E-equipment related catastrophic fires beyond what we have provided to date. This includes: (1) specific cause analysis for each identified fire analyzing the issues that led to the ignition and spread; (2) an evaluation of programmatic and systemic issues related to the cause; and (3) consideration of resources to make changes to wildfire mitigation activities.

Below we provide more information responsive to Energy Safety's requests. For clarity, we are following the format provided in response to Critical Issue 22-01 in last year's Revised 2022 WMP. In addition, we are adding the Butte Fire to the response given the broader request for information regarding catastrophic fires made by Energy Safety in

Section 5.3.2 and Section 10 of this WMP. We are also including the Mosquito Fire as a fire that may be attributable to electrical facilities, but is still under investigation, in response to the request made in Section 5.3.2. To avoid redundancy, this response will serve as the answer to the Section 10 request for lessons learned from any and each catastrophic wildfire ignited by its facilities or equipment identified in response to Section 5.3.2.

We have added additional details in Table PG&E-22-08-1, where possible, to respond to Energy Safety's requests. We also note that for more recent fires under investigation, and fires that are still in litigation, our analysis is still ongoing and subject to change.

TABLE PG&E-22-08-1:
LESSONS LEARNED FROM UTILITY-CAUSED CATASTROPHIC FIRES

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 the time of the Butte Fire, PG&E has improved employee and contractor training regarding Vegetation Management (VM) to mitigate wildfire and ensure safe work practices.
Measures to mitigate cause	Improved employee and contractor VM training.
Integration of Lessons Learned into Wildfire Strategy	We do not have specific mitigations in our 2023 WMP related to the Butte Fire because we have already improved our VM practices since that time. We have invested significant resources into our Pre-Inspector basics Training Path (formerly called the Structured Learning Path) to provide specific, well-defined training related to the work being performed. We have partnered with the International Brotherhood of Electrical Workers (IBEW) and educational institutions, such as the California Community College system, to establish a training program designed to provide the skills and knowledge necessary to perform tree crew work safely and competently. PG&E has also implemented training programs for VM employees and contractors who are responsible for VM projects. (See e.g., 2023-2025 WMP, Section 8.2.7 for Workforce Planning and training information.) We also adopted Acceptable Quality Levels for our Quality Assurance Vegetation Management and Quality Verification Vegetation Management programs. (PG&E's 2022 Revised WMP, p. 774.)

TABLE PG&E-22-08-1:
LESSONS LEARNED FROM UTILITY-CAUSED CATASTROPHIC FIRES
(CONTINUED)

Fire Name: Railroad Fire	
Date of Ignition	August 29, 2017
Cause Based on Available Information According to the USFS,	According to the United States Department of Agriculture Forest Service, a contractor was hired to remove a dead cedar tree adjacent to PG&E's powerlines in Madera County. After several cuts to the tree had been made, the tree 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. Since the time of the Railroad Fire, PG&E has improved VM training and employee and contractor training regarding work outdoors in any forest, brush, or grass-covered land.[a] In 2021, we implemented Safe Work Practices that outline safe work processes that contractors must adhere to when performing tree work.[b] If tree work cannot be performed pursuant to the safe work practices outlined because of abnormal conditions, contractors should stop work to reevaluate how to perform the work safely.
Measures to mitigate cause	Improved employee and contract VM training for responding to hazard trees in proximity to PG&E powerlines.
Integration of Lessons Learned into Wildfire Strategy	We do not have specific mitigations in our 2023 WMP related to the Railroad Fire because we have already improved our VM practices since that time. We have invested significant resources into our Pre-Inspector basics Training Path (formerly called the Structured Learning Path) to provide specific, well-defined training related to the work being performed. We have partnered with the IBEW and educational institutions, such as the California Community College system, to establish a training program designed to provide the skills and knowledge necessary to perform tree crew work safely and competently. PG&E has also implemented training programs for VM employees and contractors who are responsible for VM projects. (See e.g., 2023-2025 WMP, Section 8.2.7 for Workforce Planning and training information.)
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 of these fires based on available information: <u>Cherokee</u> – On October 8, 2017, PG&E observed that branches from a green, healthy California White Oak/Valley Oak tree had broken in Oroville. Per the troubleman who responded, one branch was found on the ground lying on top of a downed conductor. Another broken branch was suspended

TABLE PG&E-22-08-1:
LESSONS LEARNED FROM UTILITY-CAUSED CATASTROPHIC FIRES
(CONTINUED)

	in the air, hanging on another branch, and touching a conductor that remained intact. <u>Adobe</u> – According to CAL FIRE, the Adobe Fire was one of six incidents constituting the "Nuns Fire," which ignited on October 8, 2017. The Adobe Fire occurred in Kenwood. When PG&E was granted access to the incident location, PG&E observed a green Eucalyptus tree that had fallen and was laying 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. <u>Nuns</u> – According to CAL FIRE, the "Nuns fire" consists of six different fires: Nuns, Adobe, Norrbom, Pressley, Partrick and Oakmont, and it started on October 8, 2017 in Glen Ellen. 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 laying 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. <u>Sulphur</u> – According to CAL FIRE, the Sulphur incident 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 had burned at the base and fallen to the ground. This resulted in a wire down event. <u>La Porte</u> – According to CAL FIRE, this 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 a number of broken oak tree branches and a downed conductor at the incident location. <u>Pressley</u> – According to CAL FIRE, the Pressley fire started on October 9, 2017. The CAL FIRE website lists the location of the Pressley Fire as "east of Rohnert Park" in Sonoma County. Per CAL this is one of the six fires that were included in the vegetation-caused "Nuns Fire." <u>Norrbom</u> – 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. <u>Redwood Valley</u> – According to CAL FIRE, the Redwood Valley incident location was first observed on October 9, 2017. According to the CAL FIRE Investigation Report for the Redwood Incident, 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. <u>Cascade</u> – 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 CALFIRE 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 a chance 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 was at the Oakmont incident location to assist CAL FIRE on the evening of October 13, 2017, and he 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. Pocket – According to CAL FIRE's website, the Pocket incident 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. Therefore, our lessons learned addressed VM, equipment failure, and high wind weather events.

TABLE PG&E-22-08-1:
LESSONS LEARNED FROM UTILITY-CAUSED CATASTROPHIC FIRES
(CONTINUED)

	We continue to learn from past fires. The CPUC required PG&E to hire 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.[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. We address some of these items below.
Measures to mitigate cause	Vegetation Contact: In 2019, we Initiated the Enhanced Vegetation Management (EVM) Program in HFTD areas to go above and beyond regulatory requirements and address the highest risk Circuit Protection Zones (CPZ). We concluded this program at the end of 2022. Increased vegetation inspection capabilities for EVM by employing enhanced technologies such as Light Detection and Ranging (LiDAR). By 2019, we had captured LiDAR and imagery data on almost all Tier 2 and Tier 3 HFTD distribution lines. This helped to identify trees within striking distance of distribution lines to aid in the EVM inspection process. Disabled automatic reclosers in Tier 2 and Tier 3 HFTD areas to prevent potential ignitions from vegetation contact in high wind and weather events during fire season.[e] Implemented a System Hardening Program to mitigate risks associated with vegetation contact. Our system hardening work includes, but is not limited to, undergrounding overhead lines, covering conductor, and creating remote grids in HFTDs/High Fire Risk Areas (HFRA). Equipment Failures: Developed modeling and analytics to evaluate conductor to conductor contact. Evaluated the types of materials used for distribution poles for strength and resiliency to mitigate pole failures. High Winds and Weather Leading to Potential Ignitions: Developed and began implementing a PSPS Program in 2018 for distribution lines that traverse Tier 3 areas to mitigate potential ignitions from vegetation contact or equipment failure that could occur during high wind and other weather events. In 2019, PSPS was expanded to all distribution and transmission lines that traverse Tier 2 and Tier 3 HFTD areas. Since that time, we have worked to reduce the size, scope, and length of PSPS events. Installed weather stations to be more aware of local weather and wind conditions.

TABLE PG&E-22-08-1:
LESSONS LEARNED FROM UTILITY-CAUSED CATASTROPHIC FIRES
(CONTINUED)

Integration of Lessons Learned into Wildfire Strategy	Vegetation Contact: EVM was integrated into our VM Program and in 2022 we performed work on approximately 1,900 of the highest risk ranked circuit miles. We have incorporated LiDAR vegetation inspections for transmission facilities and have plans to continue to capture and update our LiDAR datasets. (2023-2025 WMP, Sections 8.2.1 and 8.2.2.1) We have continued to enhance and are developing our One Vegetation Management platform which will allow for digital work packages, tracking, and records for VM. (2023-2025 WMP, Section 8.2.4) We have Supervisory Control and Data Acquisition (SCADA)-enabled many reclosers and for reclosers that are automatic, we are continuing to disable them in HFTDs during fire season. (2023-2025 WMP, Section 8.1.8.1) We have significantly expanded our System Hardening Program, including undergrounding, which is intended to reduce the potential for vegetation caused ignitions. (2023-2025 WMP, Sections 8.1.2.1, 8.1.2.2) Equipment Failure: We are focusing our pole loading and replacement program on Tier 2 and Tier 3 HFTD areas to address potential pole failures that may lead to an ignition. In 2022, PG&E completed pole loading analysis of more than 314,000 poles, all of which are considered the highest risk poles, either due to the pole characteristics or location, being in an HFTD area. (2023-2025 WMP, Section 8.1.3.2). In addition, as a part of our System Hardening Program, we are evaluating and, where needed, replacing poles with stronger composite poles that reduce the risk of failure during wildfires. (2023-2025 WMP, Section 8.1.2.3.) Our PSPS Program addresses weather conditions including high wind events. Since conductor to conductor contact typically occurs during high wind events, the PSPS Program can mitigate the wire-to-wire contact that occurred in the Cascade Fire. (2023-2025 WMP, Section 9.2) High Winds and Weather: We have continued to evaluate and refine our PSPS Program, which is intended to prevent ignitions during high wind and other weather conditions, such as RFWs. (2023-2025 WMP, Section 9.) We are continuing to use weather stations and high-definition cameras for situational awareness of high winds and weather events. (2023-2025 WMP, Section 8.3.5.)
Fire Name: Airline Fire	
Date of Ignition	June 4, 2018
Cause Based on Available Information	The Eastern and Airline Fires started at two different points and had two different apparent causes, but they are related. The Eastern Fire resulted when a healthy tree branch leaned into a distribution pole in high winds breaking one of three conductors. (CAL FIRE determined that tree-trim activities were sufficient.) The Airline Fire was a result of the Eastern Fire vegetation contact which caused a fault current resulting in a conductor failure on a long span and a wire down.

TABLE PG&E-22-08-1:
LESSONS LEARNED FROM UTILITY-CAUSED CATASTROPHIC FIRES
(CONTINUED)

	The length of the conductor on the long span that failed following the Eastern Fire was over 600'. The long span and the natural topography around the incident pole could have contributed to wind-generated oscillation of these lines, and over time, weakened the conductor. In addition, the lengthy span was not equipped with a vibration damper.
Lessons Learned	The tree which caused the initial ignition (Eastern Fire) was healthy and CAL FIRE determined that tree-trim activities were sufficient. For this reason, there is no lesson learned associated with the Eastern Fire. The long span and the natural topography around the incident pole for the Airline Fire could have contributed to wind-generated oscillation of these lines, and over time, weakened the conductor which led to the wires down event. A vibration damper may have prevented oscillation and this ignition.
Measures to mitigate cause	As stated above, PG&E has determined from previous failure analysis, asset evaluations, and industry knowledge that wind and outside forces induced vibration can weaken conductor overtime. Further, PG&E considers vibration dampers a mitigation to the threat of conductor vibration and an asset-life extension strategy. PG&E has current standards that require the installation of vibration dampers for distribution span configurations that are exposed to high risk of vibration.[f] Additionally in 2023, PG&E published a standard with an effective date of 3/5/2023 to include spiral vibration dampers on new installations of 1/0 Aluminum Conductor Steel Reinforced (ACSR) and #2 Copper CC that are greater than 300 feet in length.
Integration of Lessons Learned into Wildfire Strategy	Upon review, our current maintenance tags do not include a field for missing vibration dampers. In 2023, PG&E will perform an extent of condition and risk evaluation of conductor vibration for the existing HFTD distribution system to identify HFTD distribution spans where dampers may be needed and risk prioritize installation of dampers with other maintenance and inspection activities across the distribution system.
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 make contact with the steel tower structure. The ensuing electrical arcing between the jumper conductor and steel tower structure caused the aluminum strands of the conductor to melt as well as a portion of the steel tower structure. 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 RFW day.
Lessons Learned	The lessons learned from the Camp Fire include: (1) the need for rigorous equipment inspections and maintenance; and (2) using 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-22-08-1:
LESSONS LEARNED FROM UTILITY-CAUSED CATASTROPHIC FIRES
(CONTINUED)

Measures to mitigate cause	<u>Enhanced Asset Inspections</u>: Initiated Wildfire Safety Inspection Program (WSIP) in 2019 to perform enhanced inspections of all PG&E overhead transmission and distribution equipment and facilities in HFTD areas. This program, which became the foundation of our current enhanced inspection program, was informed by a Failure Modes and Effects Analysis (FMEA) that PG&E conducted after the Camp Fire. The FMEA identified multiple potential points of failure on transmission assets that could cause ignitions, including wear on C-hooks and other insulator attachment hardware, and the failure points capable of visual observation were incorporated into WSIP inspection forms. A similar approach was utilized for WSIP inspections of distribution facilities. PG&E's enhanced WSIP inspections differed from our prior routine inspections in various ways, including: for transmission towers in elevated and extreme high fire threat- areas, the use of climbing and drones equipped with high-resolution- cameras; inspection forms that specifically required inspectors to check for certain potential failure modes (including worn cold end- hardware) and document the condition of various components (including cold end- hardware), regardless of whether they required repair; review of drone photographs by members of the Drone Inspection Review Team; and review and prioritization of inspection findings by Centralized Inspection Review Team, composed of qualified personnel with collective experience in engineering, inspections and maintenance. <u>Risk Modeling and Prioritized Inspections and Maintenance</u>: Develop risk models that specifically evaluate the potential for asset or equipment failure, including failure associated with asset age, environmental factors such as wind speed and direction, corrosion, and other relevant risk drivers where such a failure may result in a wildfire ignition. Use risk models to inform prioritization of highest risk maintenance tag work <u>Expanded PSPS Program</u>: In 2019, PSPS was expanded to all distribution and transmission lines that traverse Tier 2 and Tier 3 HFTD areas.
Integration of Lessons Learned into Wildfire Strategy	<u>Enhanced Asset Inspections</u>: We have implemented detailed asset inspections which are now a part of wildfire strategy for both distribution and transmission facilities in HFTD and HFRAs.[(g)] (2023-2025 WMP, Section 8.1.3.) <u>Risk Modeling and Prioritized Inspections and Maintenance</u>: We are developing sub-models for our risk modeling that specifically evaluate the potential for equipment failure. (2023-2025 WMP, Sections 6.2.1 and 8.1.3~~.)~~ We have also used risk modeling to prioritize inspections for transmission facilities. (See 2023-2025 WMP, Section 8.1.3.) PG&E is using risk modeling to proactively reduce risk from the current backlog of maintenance tags by prioritizing the highest risk tags. (2023-2025 WMP, Section 8.1.7.)

TABLE PG&E-22-08-1:
LESSONS LEARNED FROM UTILITY-CAUSED CATASTROPHIC FIRES
(CONTINUED)

Fire Name: Lonoak Fire	
Date of Ignition	June 25, 2019
Cause Based on Available Information	The fire ignited from a wire down event near King City. A PG&E electric crew foreman and distribution supervisor conducted a patrol downstream of the incident location to look for a possible source of the fault that coincided with the fire ignition. About 1.4 miles downstream of the incident location, a bird nest was located on a distribution pole. A few spans further downstream from the bird nest, bird feathers were observed attached to one of the conductors along with black marks on two of the conductors. Bird feathers were also found on the ground under the conductors where the black marks on the conductors were observed. Based on these observations, it was concluded that this fire resulted from avian contact across two phases at the bird contact location, resulting in a fault current that caused the #2 gauge Aluminum Conductor Steel Reinforced (ACSR) wire to fail at the incident location. In addition, the Alcoa Stockbridge vibration dampers used on this older conductor may have contributed to the failure of the conductor wire. PG&E had ceased installing this type of vibration damper previously.
Lessons Learned	Periodic inspection and maintenance of the equipment was not adequate for the conductor or the vibration damper. In addition, a higher-level inspection should have taken place given the presence of the Stockbridge vibration damper on a 2ACSR wire.
Measures to mitigate cause	A Corrective Action Program (CAP) event was assigned to determine the ongoing risk from vibration dampers in the field and deployed on #2 ACSR and #4 ACSR conductor wires. The team evaluated extent of risk between #2 ACSR and Alcoa Stockbridge dampers. The evaluation did not identify any specific risk. However, as circuits with #2 ACSR are identified through maintenance or planned projects, the dampers will be replaced.[h] PG&E's Overhead Inspection Job Aid was updated with photographs to demonstrate what to look for in inspections with regard to broken wire stands at the vibration damper.[i]
Integration of Lessons Learned into Wildfire Strategy	As indicated above, we have updated our job aid regarding inspections for broken wire near vibration dampers. More generally, we have implemented detail inspections and are working to improve inspection quality. Our detailed inspection processes are described generally in Section 8.1.3 of the 2023-2025 WMP. We also described the improvements made to our asset inspections in the response to Critical Issue RN-PG&E-22-08 as part of the 2022 Revised WMP.

**TABLE PG&E-22-08-1:
LESSONS LEARNED FROM UTILITY-CAUSED CATASTROPHIC FIRES
(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 on October 23, 2019. 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 the wind event on October 23, 2019.
Lessons Learned	There were two primary lessons learned from the Kincade Fire. First, 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. Second, 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.
Measures to mitigate cause	<u>Removal of Idle Facilities and Open Jumpers</u>: Immediately after the Kincade Fire, PG&E reviewed all transmission lines to determine if other energized spans not serving customer load remained in the field. Based on the review, one line segment in an HFTD area was identified and de-energized. PG&E issued revised guidance for employees and contractors regarding idle facilities and issued guidance on open jumpers to be cut as short as practical, typically 2-3 feet in length.[j] PG&E surveyed our transmission system to identify and remediate open jumpers not in compliance with new guidance. PG&E revised inspection forms so that inspectors are required to report facilities that are not serving customer load. PG&E removed remaining idle facilities in the area where the Kincade Fire was initiated. PG&E implemented plan to remove conductor and structures (where applicable) associated with approximately 70 permanently abandoned transmission lines or portions of transmission lines.[k] <u>Risk Modeling</u>: PG&E developed risk modeling intended to focus on the probability of asset failure to prioritize asset management work. As detailed in Section 6.2, the WTRM provides a forecast of the probability of failure for individual transmission equipment components based on the threats that impact the

TABLE PG&E-22-08-1:
LESSONS LEARNED FROM UTILITY-CAUSED CATASTROPHIC FIRES
(CONTINUED)

	condition of the asset, such as corrosion, decay, wear, and the hazards the equipment must withstand, such as wind. Enhanced Asset Inspections and Maintenance: PG&E implemented enhanced inspections and risk prioritized maintenance programs to address items identified during inspection (See Section 8.1.3 of the 2023-2025 WMP for a general discussion of our transmission asset inspection work.).
Integration of Lessons Learned into Wildfire Strategy	Idle Facilities: In 2022, PG&E removed 63 miles (HFTD and non-HFTD) of permanently abandoned transmission facilities in our system. In 2023, PG&E will continue to remove permanently abandoned conductor and structures associated with the 70 permanently abandoned transmission lines or portions of transmission lines we have identified Risk Modeling: We have developed the WTRM to assess risk based on the probability of equipment or an asset failure (See generally, 2023-2025 WMP, Section 6.2). The risk model allows for the future prioritization of inspections and wildfire mitigation work plans based on probability of failure and the potential consequence of a wildfire. Enhanced Asset Inspections and Maintenance: We have been implementing enhanced inspections in HFTD and HFRA areas and prioritizing maintenance in these areas. These programs are described in more detail above in the discussion of the Camp Fire. Low Cycle Fatigue: A CAP has been opened to evaluate the extent of condition for low cycle fatigue threats to the transmission overhead system. The CAP is currently open, and we expect to perform testing in 2023.
Fire Name: Grizzly Fire	
Date of Ignition	October 27, 2019
Cause Based on Available Information	Grass fire occurred in a wildlife area used for bird and elk hunting. PG&E did not evaluate or collect physical evidence at the time because none of the authorities or media reports suggested that PG&E's facilities were implicated. The fire could have resulted from overhead electrical equipment, but we are unable to determine the precipitating event(s) which may have caused an equipment failure. There was an RFW the day of ignition.
Lessons Learned	Although PG&E was unable to determine the apparent and/or contributing causes of this fire, three mitigation measures were implemented.
Measures to mitigate cause	Special Patrol of Circuit: Following investigation of the incident, and out of an abundance of caution, an additional patrol was initiated downstream from a line recloser source-side of the fire's suspected area of origin to: Verify raptor construction. Identify any spans where the conductor may be too close together, where spreader brackets could be installed, if needed.

TABLE PG&E-22-08-1:
LESSONS LEARNED FROM UTILITY-CAUSED CATASTROPHIC FIRES
(CONTINUED)

	Identification of any poles that were leaning and causing too much slack on the conductors. Identification of splice counts on each span (pole to pole). <u>Use of Wooden Pole Elk Guards</u>: Elk guards used to add additional protection to wooden poles near the suspected area of origin. <u>Evaluation of Line Spreader Devices</u>: Assessment to determine if the use of line spreader devices or other protective devices could be effective in reducing the likelihood of a potential line-to-line fault at the Incident Location (Tier 1 Non-HFTD).
Integration of Lessons Learned into Wildfire Strategy	Because the cause of the fire was not definitively determined, we have not been able to include specific lessons learned into our wildfire strategy, but we performed mitigations related to the specific incident location. However, our enhanced inspection program, described above in the discussion of the Camp Fire, identifies asset conditions that may result in ignitions and prioritizes high risk maintenance work to mitigate the potential for ignitions.
Fire Name: Drum/Lompoc Fire	
Date of Ignition	June 14, 2020
Cause Based on Available Information	On June 14, 2020, a line recloser on a 12 kV distribution circuit opened due to a line-to-line fault that was detected. PG&E dispatched troublemen to investigate the outage. Upon arrival at the incident location, the troublemen observed smoke and an electrical conductor between two poles that failed midspan. According to the Santa Barbara County Fire Department, the conductor had ignited vegetation when it contacted the ground. Though the SED cited PG&E for failure to maintain minimum clearances, PG&E determined that the spacing of conductors on the pole at both ends of the incident span exceeded the minimum clearances required by General Order 95, Rule 38, and we are unaware of any condition that would have increased the risk of the lines contacting one another in the middle of the span. Ultimately, the specific cause of the failure could not be determined.
Lessons Learned	We were not able to determine the specific cause of the conductor failure. There was no vegetation in the area and although there is bird activity, no bird carcass was found afterwards. We are improving our ignition investigation capability to be able to do more extensive analyses of these types of ignitions in the future. In addition, to the extent the fire was the result of equipment failure, our enhanced inspection program is intended to review all of our equipment and identify equipment that may fail and cause a wildfire ignition.
Measures to mitigate cause	See Camp Wildfire (describing enhanced inspection measures).
Integration of Lessons Learned into Wildfire Strategy	See Camp Wildfire (describing enhanced inspection measures). In early 2021, PG&E established the EIA Program, uniting experts in different departments, including equipment failure experts in Applied Technology Services and Asset Failure Analysis (newly-established to support this process), to better understand the causes of PG&E facility ignitions and recommend targeted corrective actions to reduce the risk of

TABLE PG&E-22-08-1:
LESSONS LEARNED FROM UTILITY-CAUSED CATASTROPHIC FIRES
(CONTINUED)

	wildfires. In regard to ignitions where equipment failure is the suspected cause, the EIA team will coordinate the collection of failed assets for testing and analysis then analyze remaining risk (Extent of Condition) to inform wildfire mitigation strategies. (See Sections 10 and 11 of the 2023-2025 WMP for additional details regarding PG&E's wildfire investigation work and communications of lessons learned.)
Fire Name: Zogg Fire	
Date of Ignition	September 27, 2020
Cause Based on Available Information	According to CAL FIRE, on September 27, 2020, 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 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.
Measures to mitigate cause	Vegetation Contact: See October 2017 Fires for discussion of mitigations implemented regarding vegetation contact. Public Safety Power Shutoff: We modified our PSPS Protocols to include locations with tree over-strike potential in the 70th percentile or above. This was described in more detail in our 2021 WMP. (2021 WMP, p. 980)
Integration of Lessons Learned into Wildfire Strategy	Vegetation Contact:[l] EVM was integrated into our VM Program and in 2022 we performed work on approximately 1,900 of the highest risk ranked circuit miles. Given the effectiveness of the EPSS Program and resources required for EVM, we will no longer be performing EVM work in 2023. However, we will be continuing some EVM procedures in high-risk areas. (See 2023-2025 WMP, Section 8.2.3.4.) We have incorporated LiDAR vegetation inspections for transmission facilities and have plans to continue to capture and update our LiDAR datasets. (2023-2025 WMP, Sections 8.2.1 and 8.2.2.1) We have SCADA-enabled many reclosers and for reclosers that are automatic, we are continuing to disable them in HFTD Tier 2 and 3 areas during fire season. (2023-2025 WMP, Section 8.1.8.1.2) We have significantly expanded our System Hardening Program, including undergrounding, which is intended to mitigate the potential for vegetation caused ignitions. (2023-2025 WMP, Section 8.1.2.)

TABLE PG&E-22-08-1:
LESSONS LEARNED FROM UTILITY-CAUSED CATASTROPHIC FIRES
(CONTINUED)

	PSPS: We have continued to evaluate and evolve our PSPS protocols. We have incorporated tree-overstrike potential as a key attribute in our PSPS models that are based on artificial intelligence and machine learning. (See 2023-2025 WMP, Section 9.2 for additional information.) We have incorporated high-risk vegetation and asset tags into our PSPS protocols so that we can inform the scope of PSPS events, appropriately, to address this potential risk.[(m)] (2023-2025 WMP, Section 9.2.)
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. PG&E's investigation is ongoing and may lead to the implementation of additional measures.
Measures to mitigate cause	Enhanced Powerline Safety Settings: The EPSS Program was implemented following the Dixie Fire to reduce the potential for vegetation contact resulting in an ignition. It is not weather dependent like PSPS. EPSS has been enabled on all HFRA and EPSS buffer area distribution circuits in our service territory based on Fire Potential Index conditions and criteria approved by our Wildfire Risk Governance Steering Committee. While EPSS has been shown to reduce ignitions, it can lead to more frequent outages, as it inverts the typical system protection plan. Outage Response Times: After the Dixie fire, PG&E targeted responding safely to any outages in Tier 2 and Tier 3 HFTD areas like we would for a 9-1-1 emergency—with a goal of 60 minutes. In early 2022, that was refined and aligned with EPSS circuit enablement—which are turned on when there are conditions of heightened wildfire risk in HFRA and the EPSS buffer areas. Our goal is to respond to outages on EPSS-enabled circuits within 60 minutes or less.[(n)] Undergrounding: After the Dixie Fire, PG&E announced a plan to underground 10,000 of distribution powerlines in high fire risk areas. Undergrounding powerlines will help reduce vegetation contact ignitions. (2023-2025 WMP,

TABLE PG&E-22-08-1:
LESSONS LEARNED FROM UTILITY-CAUSED CATASTROPHIC FIRES
(CONTINUED)

	Section 8.1.2.2.) From 2023-2026, PG&E intends to underground 2,100 circuit miles of distribution lines in high fire risk areas. We note that the circuit associated with the Dixie Fire was in the scoping process for undergrounding in 2021 before the fire occurred.
Integration of Lessons Learned into Wildfire Strategy	EPSS: The EPSS Program was implemented following the Dixie Fire to reduce the potential for vegetation contact resulting in an ignition. It is not weather dependent like PSPS. EPSS has been enabled on all HFRA and EPSS buffer area distribution circuits in our service territory based on Fire Potential Index conditions and criteria approved by our Wildfire Risk Governance Steering Committee. While EPSS has been shown to reduce ignitions, it can lead to more frequent outages, as it inverts the typical system protection plan. Outage Response Times: After the Dixie fire, PG&E targeted responding safely to any outages in Tier 2 and Tier 3 HFTD areas like we would for a 9-1-1 emergency—with a goal of 60 minutes. In early 2022, that was refined and aligned with EPSS circuit enablement—which are turned on when there are conditions of heightened wildfire risk in HFRA and the EPSS buffer areas. Our goal is to respond to outages on EPSS-enabled circuits within 60 minutes or less. Undergrounding: After the Dixie Fire, PG&E announced a plan to underground 10,000 of distribution powerlines in high fire risk areas. Undergrounding powerlines will help reduce vegetation contact ignitions. (2023-2025 WMP, Section 8.1.2.2.) From 2023-2026, PG&E intends to underground 2,100 circuit miles of distribution lines in high fire risk areas. We note that the circuit associated with the Dixie Fire was in the scoping process for undergrounding in 2021 before the fire occurred.
Fire Name: Mosquito Fire	
Date of Ignition	September 6, 2022
Cause Based on Available Information	According to CAL FIRE, the Mosquito Fire began on September 6, 2022 near OxBow Reservoir in Placer County near PG&E transmission (60 kV) facilities. PG&E has not observed down conductor in the area or any vegetation related issues. The cause of the fire is under investigation.
Lessons Learned	There are currently no lessons learned from this ignition because its cause is still under investigation.
Measures to mitigate cause	N/A see Lessons Learned.

Integration of Lessons Learned into Wildfire Strategy	N/A see Lessons Learned.

(a) Preventing and Mitigating Fires While Performing PG&E Work Standard (TD-1464S). See Appendix E.

(b) Chainsaw Operation for Vegetation Management (TD-7101M-11), Rev 0 (2/1/2022). See Appendix E.

(c) Envista Forensics, *Root Cause Analyses of the 2017-18 Wildfires*, (July 6, 2022). See Appendix E.

(d) Comments of Pacific Gas and Electric Company on Envista Forensic's Final Root Cause Analysis Report, (August 4, 2022). See Appendix E.

(e) Enhanced Powerline Safety Settings (EPSS) and Patrol Process (TD-2700P-26), (11/24/2022) (EPSS settings now disable reclosing). See Appendix E.

(f) Vibration Damper Requirements for Various Types of Overhead Conductors, 015073, Rev. #5 (12/17/2020). See Appendix E.

(g) Job Aid: Overhead Inspection (TD-2305M-JA02), Rev. 9 (March 23, 2022); Transmission Patrols and Enhanced Inspection Frequency Guidelines (TD-8123P-100), Rev. 0 (03/12/2022); Electric Transmission Line Guidance for Setting Priority Codes (TD-8123P-103), Rev. 0 (01/03/2023). See Appendix E.

(h) Vibration Damper Requirements for Various Types of Overhead Conductors, 015073, Rev. #5 (12/17/2020). See Appendix E.

(i) Job Aid: Overhead Inspection (TD-2305M-JA02) (3/23/2022). See Appendix E.

(j) Overhead Transmission Line Design Criteria, Doc No. 068177, Rev. 14, (12/17/2020). See Appendix E.

(k) PG&E Removal Plan for Permanently Abandoned Transmission Facilities. See Appendix E.

(l) In 2022, we conducted a pilot program to perform a visual inspection of all sides of a potential strike tree on routine VM patrols in HFTD areas. We are still evaluating the results of the pilot and have not yet made changes to our processes or procedures.

(m) Public Safety Power Shutoff for Transmission and Distribution Procedure (PSPS-1000P-01), 9/1/2022. See Appendix E.

(n) Enhanced Powerline Safety Settings (EPSS)-Electric Operations Restoration Dispatch Requirements (TD-2202P-01) (11/01/2022). See Appendix E.

ACI PG&E-22-09 – Evaluation of Model Reprioritization and Fire Rebuild in High-Risk Areas

Description:

PG&E lacks vetting of the accuracy of its version three (V3) risk model compared to its version two (V2) risk model, including future vegetation projections in fire rebuild areas. This is important given its changes in modeling future vegetation growth.

Required Progress:

In its 2023 WMP, PG&E must provide further details and analysis on how its model output changed risk scores and resulting prioritization of work. This must include:

- *Analysis on the impact that specific changes to mapping methodology had on risk scores and prioritization of work. This should include confidences in risk model outputs between V2 and V3, as well as a list of projects that were de-prioritized through changes implemented between V2 and V3 of the model; and*

- *Description of the type of fuel mapping being completed to evaluate the future risk in fire scars, including details on the analysis completed to determine the most accurate fuel cases being used.*

PG&E Response:

Mitigating wildfire risk posed by utility assets is a rapidly evolving area of practice where improvements are achieved through the adoption of data and methods. As such, PG&E's WDRM has evolved—and improved—over time. As highlighted by the Independent Safety Monitor Quarterly Report, dated October 2022, "PG&E's wildfire risk models have seen considerable refinement, incorporating such things as advanced machine learning, the introduction of increasing sources of historical ignitions, greater geographic granularity and environmental inputs, distance weighting, and the use of more advanced wildfire spread and consequence formulation over time."[197] Figure PG&E-22-09-1 highlights the evolution and improvements from WDRM v1 to WDRM v3.

[197] PG&E Independent Safety Monitor Status Update Report, Filsinger Energy Partners, (October 4, 2022) (Filsinger, October 2022), p. 19. See Appendix E.

FIGURE PG&E-22-09-1:
EVOLUTION AND IMPROVEMENTS – WDRM V1 THROUGH WDRM V3

Evolution and Improvements of PG&E's Wildfire Distribution Risk Model

		2019 WDRM v1	2021 WDRM v2	2022 WDRM v3
Probability	Exposure	HTFD T2/3	HTFD T2/3	**Service Territory**
	GIS Vintage	2018	2018v/2020c	**January 2022**
	Risk Event	2015-2018 Ignitions	2015-2019 Ignitions	**2015-2021 Failures/ 2015 – 2020 Ignitions**
	Vegetation	Yes	Yes	Yes
	LiDAR Data	No	No	**Yes**
	Conductor	Primary	Primary	Primary and Secondary
	Support Structures	No	No	**Yes**
	Transformers	No	No	**Yes**
	Compositing	No	No	Yes
	Mitigation Effectiveness	No	No	Yes
Consequence	Exposure	HTFD T2/3	HTFD T2/3	**HTFD + Burnable Tier 1**
	GIS Vintage	July 2016	April 2019	**January 2022**
	Fuels	2012 LANDFIRE	2020 Fuels Snapshot	**2030 Forecast Growth**
	Simulation Duration	6 Hours	8 Hours	8 Hours
	Consequence Formulation	Reax Index comp. Volume and Structures	FBI >=2 and Acres >= 300 and Buildings >= 50, OR FBI >=3	**FPI >= R4, OR FL >= 5 and ROS >= 12**

A natural byproduct of these improvements is that risk prioritization rankings can and will change. PG&E continues to emphasize that risk models are a statistical analytical approach to approximating and estimating the risk of wildfire which is a dynamic risk. As such, outputs from successive risk models will shift with the update of each additional year of events (outages and ignitions) as well as modeling improvements. Between WDRM v2 and v3 several factors resulted in shifts to circuit segment prioritization. What follows is a description of the modeling improvements, data improvements, resulting shifts in prioritization, and locations of projects that were deprioritized.

Modeling Improvements

Version 1 (v1) – 2019

In 2019 PG&E started to prioritize circuits and circuit segments for wildfire risk mitigation using our v1 model. Ignition probability was derived from outage and ignition data using a logistical regression model. Wildfire consequence predictions came from fire modeling software vendor REAX Engineering.

The WDRM v1 supported mitigation work conducted from 2019-2021.

Version 2 (v2) – 2020-2021

The second generation of the WDRM took a meaningful step forward by using more advanced modeling, examining more sub-drivers with regards to ignitions, and using

PG&E's MAVF to predict wildfire consequences. The v2 model used more advanced algorithms and machine learning.

PG&E also improved the modeling so that it was more granular spatially and by risk driver. The spatial resolution of the model was improved from circuits in v1 to 100 x 100-meter (m) areas (pixels) in the HFTD in v2. In addition, we modeled vegetation-caused ignitions separately from other ignitions along conductor lines to understand these two risk drivers. This resulted in two related but separate models (i.e., vegetation-caused and conductor-involved), each of which was used by a different wildfire risk mitigation program (EVM and System Hardening, respectively).

V2 was also upgraded to use physics-based fire simulation outputs provided by vendor Technosylva, mapped into MAVF fire size/severity tranches based on their simulated characteristics, to quantify wildfire consequence.

Version 3 (v3) – Modeling in 2021 for Use Starting in 2022

For the WDRM v3 model, PG&E implemented numerous improvements based on internal review and feedback from public safety specialists, other partners, interveners, and a third-party review. This version uses more-advanced machine-learning modeling techniques, incorporates improved and updated data, adds predictions of wildfire risk reduction when mitigating various sources of risk, expands to understand additional ignition sources and sub-drivers, and more.

This version also models several "causal pathways" to ignitions separately, allowing for the nature of these causes to inform the type of model structure and relevant covariates. This also allows for a more specific mapping between cause categories and the mitigations that address them.

Data Improvements

WDRM v3 model data improvements have focused on three areas: (1) event data (outage, PSPS damages, and ignitions); (2) model inputs (covariate), for the probabilistic (Likelihood of a Risk Event) models; and (3) wildfire simulation data and historical fire records in the development of the wildfire consequence (Consequence of Risk Event) models.

Updated and Expanded Outage and Ignition Training Event Data

PG&E has a rich set of ignition data starting in 2015. The WDRM v3 model estimates both the probability of outage and probability of ignition from outages using outage and ignition data through 2020 (where outage data includes imputed data from damages incurred when the power was off for PSPS events) to enable more detailed dissection of data by cause and equipment involved without the loss of predictive power.

More Accurate, Covariate Data Inputs

The WDRM v3 includes more accurate inputs such as tree data from a combination of LiDAR and satellite data, updated weather data from PG&E's meteorology team, tree species data, and predictions from PG&E's pole loading simulation program.

An Improved Wildfire Consequence Model

We significantly upgraded the wildfire consequence model using improved wildfire simulation data and calibration with historical fire records to provide improved predictions. In line with an E3[198] report recommendation, the planning and operational versions of wildfire consequence were developed from a common core data set and framework. This has improved the coordination between the two models.

The fuels layer used in the Technosylva fire simulation was updated to replace current fire scars with a 2030-fuels forecast. As described in PG&E's 2022 WMP,[199] the switch to a 2030 forecasted fuels layer was based on the view that pre-fire vegetation levels best represent the long-term ground fuel potential.

"For long-term risk assessment, PG&E utilized a projected fuel layer for the year 2030 that was provided by Technosylva. The intent is that the planning model is used to make longer-term decisions to reduce risk and we wanted to capture the potential future state of the fuels. Technosylva utilized their expertise in vegetative re-growth after fire disturbances (fire scars) to project the state of the fuels in 2030. This work leverages historical data on vegetation regrowth after fires based on satellite data and burn severity maps."[200]

This decision was made in consultation with our Wildfire propagation and consequence modelling provider, Technosylva. Technosylva provides a fuels data updating subscription used by PG&E and other IOUs that ensures surface and canopy fuels data is kept up to date during the calendar year. This is important to ensure daily fire behavior and risk analysis is accurate. This typically involves updates pre-season (July), post-season (December), and regular updates during fire season based on the frequency of large wildfires. Pre and post-season updates include incorporating new data sources, such as LiDAR and other imagery, available from both public and commercial sources. Updates conducted during fire season use high resolution imagery sources to conduct burn severity mapping to provide fuels updates for burn areas.

Shifts in Risk Prioritization

Due to changes in the categories of events modeled, the geographic territory covered, and circuit segment name and circuit geometry changes, there is no direct comparison between v2 and v3.

The closest comparison is a comparison of the vegetation models. In v2 of the WDRM, the vegetation model had an overall Receiver Operator Characteristic – Area Under the Curve (AUC) score of 0.73, while v3 (which models trunks, branches, and other

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[198] E3 is Energy, Environment and Economics, an independent third-party who evaluated PG&E's wildfire risk models.

[199] See PG&E's 2022 WMP (July 26, 2022), Section 4.5.1(d) Wildfire Consequence Model and an August 2022 Data Response to OEIS (OEIS_016-Q02).

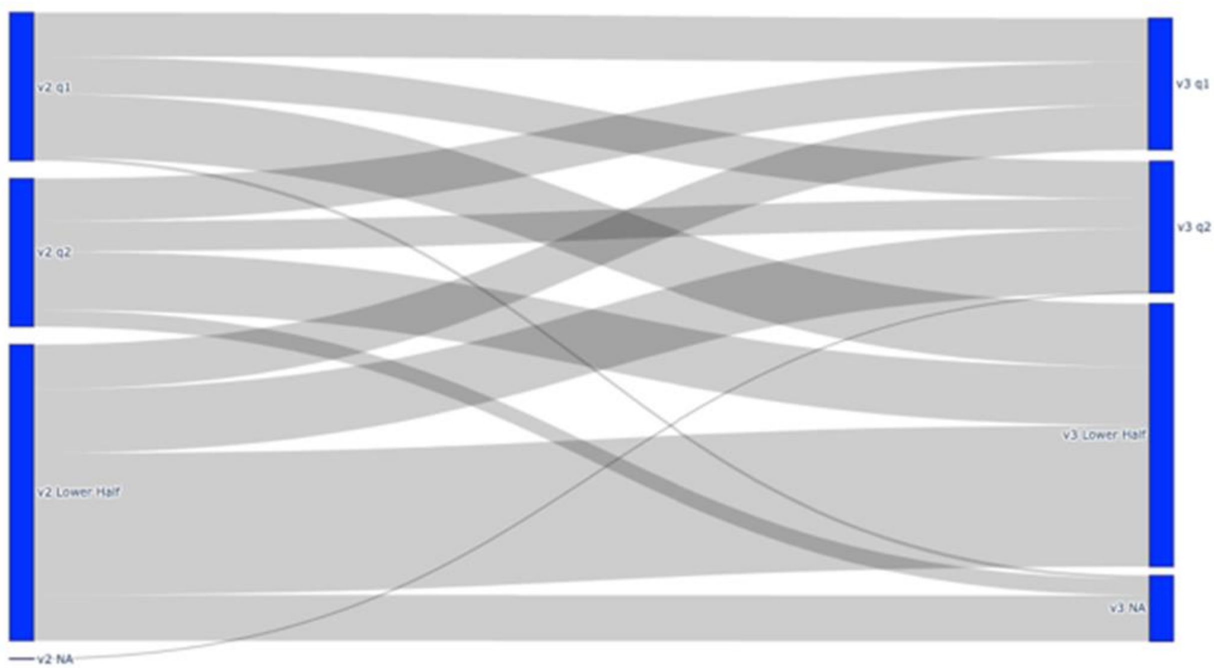
[200] PG&E's 2022 WMP (July 26, 2022), p. 183.

attributes separately) shows an improvement over v2 with an AUC score for the vegetation composite of 0.78.

Nevertheless, if the resulting HFTD circuit segment prioritization for the System Hardening composite from the v2 and v3 model are compared, the movement of circuit segments can be observed. The Sankey chart below (Figure PG&E-22-09-2) displays movement between the top two quartiles and the lower 50 percent from the v2 model on the left to the v3 model on the right. The following observations correspond to flows on the Sankey chart:

- 25 percent of v3 1st and 2nd quartile circuit segments are new and were not present in the v2 model;
- The majority of new v3 circuit segments are ranked in the lower half in the v3 model; and
- Approximately one-third of v2 1st and 2nd quartile circuit segments move to the lower 50 percent in v3.

FIGURE PG&E-22-09-2:
SANKEY VIEW SYSTEM HARDENING CIRCUIT SEGMENT RISK, v2 VS. v3



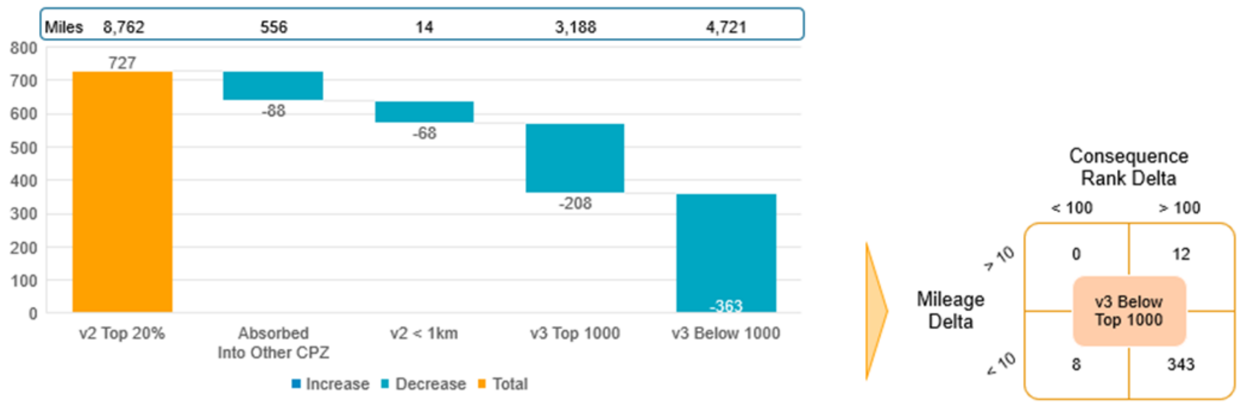
In most cases, the central cause of changing risk was updated consequence values. The following causes were also found to play a role:

- Geometry changes including addition, subtraction, and the splitting of the CPZ into two or more distinct circuit segments in v3;
- Name changes including the absorption of CPZs into others resulting in the original CPZ no longer existing;

- The handling of CPZs that were partially included in HFTDs. In v2, the total risk was found by only summing those risk pixels belonging to the CPZ whose centroid was within the HFTD while in v3, all pixel risks belonging to the CPZ were summed whether or not it was included in the HFTD.

We studied risk changes for those circuit segments which were in the top 20 percent of risk in v2 but had dropped out of the top 20 percent in v3 as shown in Figure PG&E-22-09-3 below.

FIGURE PG&E-22-09-3:
CIRCUIT SEGMENTS IN THE TOP 20% IN v2,
BUT NOT IN THE TOP 20% IN v3



<u>Of the 727 circuit segments in the top 20 percent of v2 risk</u>:

- 88 were absorbed into another circuit segment name; and
- Another 68 circuit segments were less than 1km long.

<u>Of the remaining 571 circuit segments</u>:

- 208 remained in the v3 top 20 percent (or top 1,000).

<u>Of the top 727 circuit segments in the v2 top 20 percent</u>:

- 363 dropped to the lower 80 percent.

<u>Of these 363 circuit segments</u>:

- Most of moves (343) were dominated by a large shift in the wildfire consequence value and rank;
- A small portion of these moves (12) were influenced by both a large shift in the circuit segment mileage and wildfire consequence; and
- 8 circuit segments moved due to a shift in the ignition probability and were minimally influenced by wildfire consequence or a change in length.

The two figures below (Figure PG&E-22-09-4 and Figure PG&E-22-09-5) illustrate these movements between the two versions of the risk model:

FIGURE PG&E-22-09-4:
SANTA YNEZ 1104CB – LARGE CONSEQUENCE CHANGE, SMALL MILEAGE CHANGE

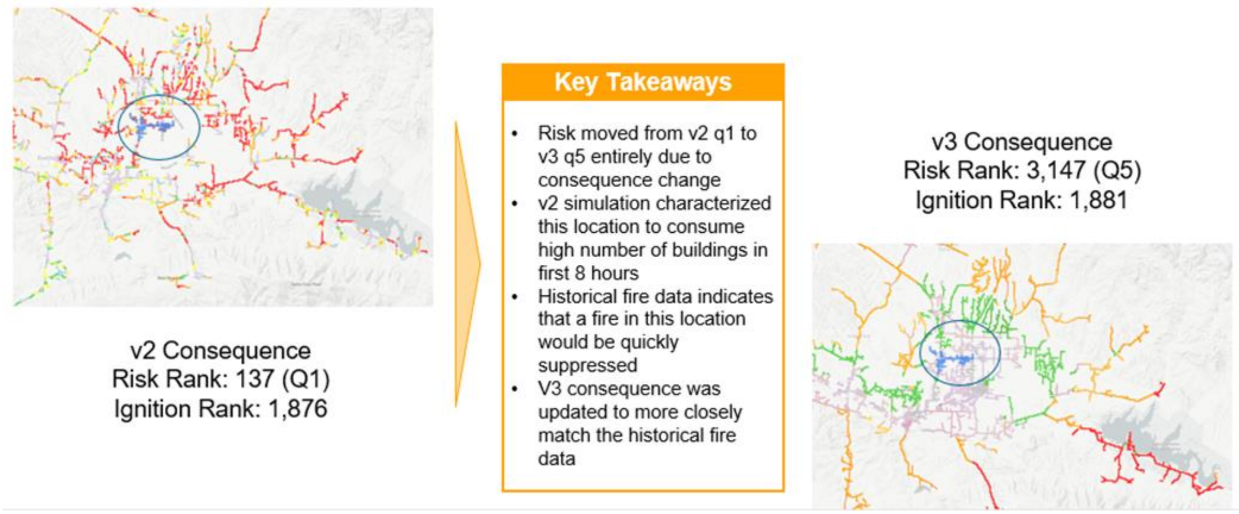
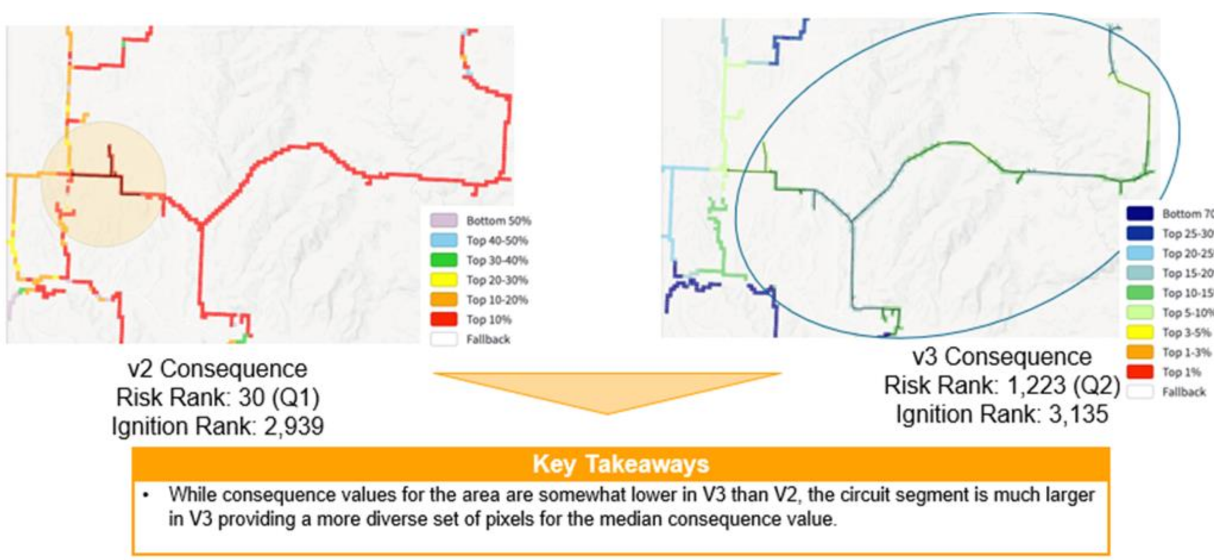


FIGURE PG&E-22-09-5:
POSO MOUNTAIN 2103CB – SMALL CONSEQUENCE CHANGE, LARGE MILEAGE CHANGE



Project Impacts

Because of the relationship between when WDRM v3 was approved and the development of workplans, there were no projects that were de-prioritized from the changes implemented between V2 and V3 of the model.

As summarized and highlighted by in the ISM Quarterly report:

“Since the wildfire mitigation work plans for EVM and system hardening for 2021 and 2022 have been focused on working on CPZs at the top of the V2 risk ranking, some of this completed and still in-progress work has/is continuing to be done on CPZs that the latest model has now identified as lower risk. For the WMP EVM programs, work in 2021 was primarily focused on CPZs risk ranked 1 to 100 using a tree-weighted adjustment (as detailed in the WMP) to the V2 model. For 2022, the EVM work is focusing primarily on CPZs ranked using same model from 101-253. Given annual work plan horizons, and the approval of V3 of the model in April 2022, the first EVM, system hardening and distribution inspection work plans that are anticipated to be risk informed by V3, are not scheduled to begin until 2023.

As previously noted, system hardening projects can take years between when they are initially scoped, and when construction may begin. During such an extended period, changes to the risk models have been occurring, with accompanying shifts in CPZ risk rankings. As a result of these changes, previously approved system hardening projects have not yet initiated construction on CPZs that are now ranked as much lower risk.

With the release of V2 in late 2020, PG&E directed the reprioritization of the System Hardening Program, halting many projects and placing them on-hold pending reevaluation. Throughout 2020 and 2021, these projects were reevaluated, and many were brought back into the workplan for reasons such as EPSS Recommendations, CalTrans Design Standard Decision Document pilot, and PSPS lookback changes. PG&E elected to hold and wait until the release of V3 to complete the final opportunity assessment and then decide whether to cancel several projects scheduled to occur on CPZs now deemed lower risk.

The shifting of the distribution circuit/CPZ risk rankings between model versions over the past five years also has the unintended consequence of making it appear as if much of the previous EVM and system hardening work was focused on areas now forecast to have lower risk.”[201]

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[201] Filsinger October 2022, pp. 21-22. See Appendix E.

ACI PG&E-22-10 – Justification of Weather Station Network Density

Description:

PG&E reports meeting its targeted goal of deploying 1,300 weather stations. However, comparing weather station density to peer utilities, PG&E has fewer weathers stations installed per circuit mile than its peers.

Required Progress:

In its 2023 WMP, PG&E must explain how the long-term goal of 1,300 weather stations was determined and that this number provides sufficient granularity. This analysis must address how spatial gaps in its network have been identified.

PG&E Response:

During the 2018 launch of the weather station program, PG&E consulted with meteorologists, analysts, and external parties—as well as benchmarked with other California IOUs—to help us determine the weather station density we should install in the HFTD areas across our territory. We determined that a weather station situated approximately every 20 overhead lines miles would be appropriate in these areas, which equated to around 1,300 weather stations.[202] Our network complements existing state and federally owned and maintained weather stations (e.g., National Weather Service and Remote Automated Weather Stations), which we also use for situational intelligence.

In 2019 the California Energy Commission (CEC) awarded a $5 million dollar grant to advance California's wildfire science capabilities. Part of the grant, which was awarded to an external party, was to determine the optimal density and configuration of weather stations for electrical utilities. We met with this party's project teams to obtain preliminary access to reports, and we also serve as a member on the Technical Advisory Board that provides feedback into this and related projects.

This external study funded by CEC grant EPC-18-026 used a Maximum Entropy algorithm to classify and identify areas with similar climate to locations that already have weather stations, and areas with climate conditions that are not well measured by current stations. The result was a continuous grid of similarity scores, which indicate how similar/dissimilar a new weather station would be relative to the existing network(s). Low similarity scores help identify areas where additional weather stations may need to be installed.[203]

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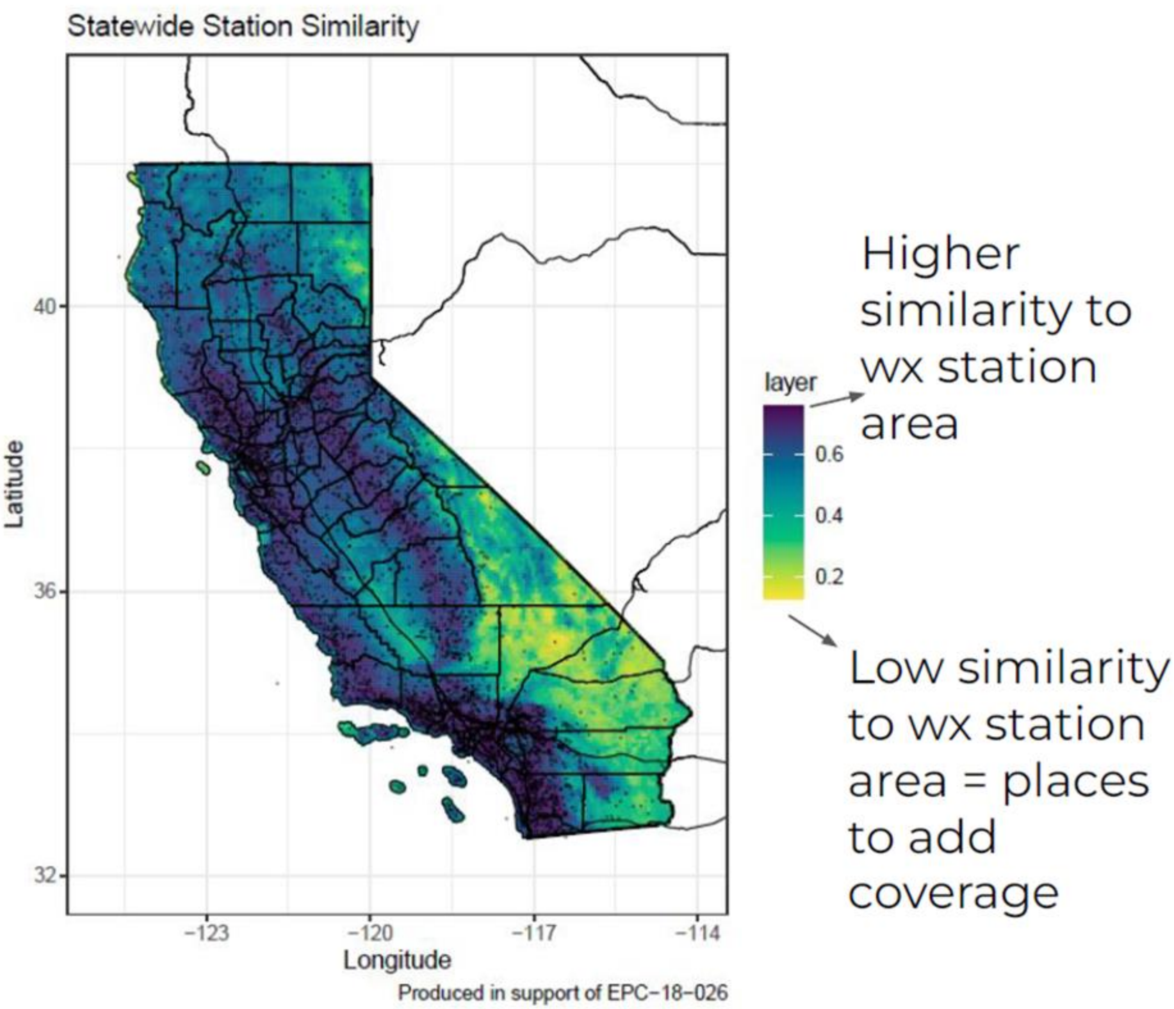
202 See PG&E's 2019 WMP (Feb. 6, 2019), Section 4.5.3, pp. 90-91.

203 Based on an advanced copy of the external study.

The statewide similarity scores from this external study are shown in Figure PG&E-22-10-1 below. The areas with the lowest similarity scores are in the Tier 1 Central Valley in the PG&E service territory—as well in the highest terrain in the Sierra Nevada—where PG&E assets are few and installations in USFS land take years to complete due to permitting lead times.

FIGURE PG&E-22-10-1:
STATEWIDE STATION SIMILARITY SCORES



This study supports the current density of weather stations in the PG&E territory, confirming that it is largely sufficient given the small area of low similarity scores. The final report notes that, ". . . for fire weather purposes, it may be necessary to position additional weather stations in canyons and other regions where short-term winds can rapidly spread wildfires."

PG&E strongly believes that the external study supports our 2019 conclusion that 1,300 weather stations would "…provide PG&E with sufficiently granular knowledge of local conditions to appropriately guide its wildfire risk reduction measures."[204]

While our weather station network is nearing full maturity, we plan to install more stations in the Tier 1 areas to improve situational awareness and work through permitting challenges to install additional sites in the coming years in federal lands. We also welcome and encourage additional weather station installations from state and federal agencies and continue to leverage those networks to enhance our capabilities.

204 PG&E's 2019 WMP (Feb. 6, 2019), p. 91.

ACI PG&E-22-11 – Covered Conductor Effectiveness Lessons Learned

Description:

PG&E has not yet provided goals or timelines for implementing lessons learned from the CC joint effectiveness study

Required Progress:

In its 2023 WMP, PG&E must:

- Provide a concrete list of goals with planned dates of implementation for any *lessons learned in the CC effectiveness joint study;*
- *Provide a table indicating which WMP sections include changes (compared to its 2021 and 2022 Updates) as a result of the CC effectiveness joint study. This should include, but not be limited to:*
  - *Changes made to CC effectiveness calculations;*
  - *Changes made to initiative selection based on effectiveness and benchmarking across alternatives;*
  - *Inclusion of Rapid Earth Fault Current Limiter, Open Phase Detection, Early Fault Detection, and Distribution Fault Anticipation as alternatives, including for PSPS considerations;*
  - *Changes made to cost impacts and drivers; and*
  - *An update on data sharing across utilities on measured effectiveness of CC in-filed and pilot results, including collective evaluation.*

PG&E Response:

In 2022, the joint California IOUs continued to work on the Joint CC Effectiveness Study (Joint IOU Covered Conductor Working Group Report)[205] to better understand the advantages, operative failure modes, and current state of knowledge regarding CCs.

A summary of the learnings for each of the following sub-workstreams is provided below: Testing; Estimated Effectiveness; Additional Recorded Effectiveness; Alternative Technologies; and Cost and Impact Drivers.

Goals and Timeline for Implementation

Table PG&E-22-11-1 below lists PG&E's goals related to lessons learned from the CC effectiveness study and the timeline for implementing them. The table also includes a reference to the section of the WMP where we discuss changes associated with the lesson learned.

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[205] Attachment 2023-03-27_PGE_2023_WMP _R0_Appendix D ACI PG&E-22-11_Atch01.

TABLE PG&E-22-11-1:
COVERED CONDUCTOR EFFECTIVENESS STUDY
LESSONS LEARNED – GOALS AND TIMELINES

Goal	Timeline for Implementation	WMP Section Changes
Incorporate Phase 1 and Phase 2 Testing Findings	A new inspection checklist question for detecting CC damages has been added to 2023's inspection checklist for execution. Findings will be further reviewed to assess if additional updates to Inspection and Maintenance standards are required in 2023 for 2024 implementation.	ACI PG&E-22-11
Updates to CC Effectiveness	Estimated Effectiveness was updated in January 2023 Recorded Effectiveness Preliminary Results as developed in January 2023; Re-assessment of Recorded Effectiveness using 2023 data for January 2024.	ACI PG&E-22-11
Changes to initiative selection based on effectiveness and benchmark	Preliminary Results were consistent with existing effectiveness figures, so there are currently no changes to the recommended initiative selection based on 2023 data in January 2024.	ACI PG&E-22-11
Incorporation with Alternative Technologies	In January 2023, PG&E evaluated, in cooperation with Joint IOUs, incorporation of alternative technologies with CCs; no further action at this time.	Joint IOU Covered Conductor Working Group Report[a]
Changes in Cost & Drivers	In January 2023, PG&E updated our cost drivers year-over-year, acknowledging the impact of location, and labor. Breakdown of units performed per year, was also performed in January 2023 and included in the Joint IOU study.	ACI PG&E-22-11
Update on Data Sharing on Measured Effectiveness	In January 2023, PG&E shared via Joint IOU CC measured effectiveness.	Joint IOU Study

(a) Attachment 2023-03-27_PGE_2023_WMP _R0_Appendix D ACI PG&E-22-11_Atch01.

CC Testing

CC testing was performed in 2 phases. The Phase 1 objectives were to:

- Develop IOU-agreed CC FMEA;
- Summarize current testing/knowledge of CC performance; and
- Identify gaps in current testing/knowledge and practices/implementation.

The Phase 1 Final Report was published by Exponent in February 2022.[206]

206 Available at: https://efiling.energysafety.ca.gov/eFiling/Getfile.aspx?fileid=52749&shareable=true.

For the remainder of 2022, PG&E and the other IOUs executed Phase 2 of the CC effectiveness study. The Phase 2 objectives were to:

- Develop test plans based on Phase 1 report identified gaps and recommendations.
- Complete physical testing of CC; and
- Document results from physical testing of CC.

In Phase 2, SCE, SDG&E, and PG&E executed different elements of the testing as part of the joint IOU effort. The results of the testing will be included in the final report that was completed in February 2023 and is attached to this plan.[207] PG&E's testing included:

- Dimensional analysis;
- Filler content analysis;
- Water absorption;
- Fourier-transform infrared spectroscopy;
- Heat shrinkage;
- Differential scanning calorimetry;
- Flammability;
- Tensile;
- Accelerated corrosion;
- Water ingress;
- Water immersion;
- Ultraviolet weathering;
- Leakage current and dielectric strength;
- Tracking resistance;
- Tracking resistance with salt fog; and
- Lightning.

[207] Attachment 2023-03-27_PGE_2023_WMP _R0_Appendix D ACI PG&E-22-11_Atch02.

Most of the tests were conducted per American National Standards Institute (ANSI), Insulated Cable Engineers Association (ICEA), or European Norm (EN) standards. The testing occurred June to December 2022 and the final testing report was published in December 2022.[208]

In 2023, based on the results of the study and SME discussion, PG&E updated our inspection checklist to include a specific question for identifying failure modes that are unique to CC. PG&E will continue to review the findings from the study and evaluate any additional changes that are necessary in the following areas:

- Maintenance and inspection practices specific to CC;
- CC estimated effectiveness;
- CC recorded effectiveness; and
- Cost impacts and drivers.

Covered Conductor Estimated Effectiveness

Based on the work conducted through the joint IOU study, PG&E is comparing our existing SME estimated effectiveness designations with the findings from the study. While this is expected to be an ongoing process, we have refreshed our estimated effectiveness values based on updated designations and the data as follows:

- Tree fall-in associated with wire on object, and wire on ground, changed from “None” (not effective) to “Medium” (some effectiveness). While other IOUs considered a higher effectiveness than PG&E, there are large enough trees in our service territories that can damage CC and therefore CC does not have as substantial an increase in effectiveness in this case.
- Contact from Object Vehicle changed from “None” (not effective) to “Medium” (some effectiveness). We agree with other IOUs that this has some limited benefit. Given that we are installing larger poles to support CCs, the larger poles have the potential to sustain more impact from vehicle than existing infrastructure.
- Animal caused outages associated with conductor contact changed from “None” (not effective) to “All” (very high effectiveness). Testing on the covering material of the CCs showed a high resiliency to damage. PG&E found the insulating properties of the covering did not diminish significantly when damaged. Therefore, we have increased CC effectiveness for mitigating damage caused by animals like squirrels and birds.

Additionally, we have refreshed our data for estimated effectiveness to include outage data through 2022. We also expanded the study to include all outages throughout the entire year instead of only on high wind days. Previously, the last update was from PG&E’s 2023 GRC filing, which had data through 2020. Based on the latest update

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[208] Instructions for viewing the Joint-IOU Covered Conductor Testing Cumulative Report (December 22, 2022) located in Appendix E

using data through 2022, the estimated effectiveness is 64 percent. This is consistent with the previous results that were completed using data through 2020.

Covered Conductor Recorded Effectiveness

PG&E will continue to use estimated effectiveness to represent system hardening overhead effectiveness until more data points are available to support recorded effectiveness values. At the end of 2022, there were approximately 960 miles of overhead CCs installed on our system. The number of ignitions observed on the CC lines to date does not provide enough data to reach a conclusion about recorded effectiveness that is statistically significant.

Though we have limited ignition data on CCs, we calculated a preliminary range for recorded effectiveness of overhead hardening by applying the following proxy. Most distribution outages (momentary and sustained) typically involve a fault condition. Thus, for purposes of estimating overhead hardening recorded effectiveness, we assume that all distribution outages can potentially result in an ignition, regardless of other prevailing conditions, to capture more data points for measurement.

PG&E is measuring the recorded effectiveness of CC by comparing the outages on the circuit segments with CCs to outages on circuit segments with bare conductors. The comparison was conducted on an outages-per-year, per-mile basis to normalize outage rates pre- and post-CC. Table PG&E-22-11-2 below presents the results of this preliminary recorded effectiveness analysis.

TABLE PG&E-22-11-2:
PRELIMINARY RECORDED EFFECTIVENESS ANALYSIS

	Miles Overhead Hardened as of End -of-Year (EOY) 2019[(a)]		Miles Overhead Hardened as of EOY 2020[(b)]		Miles Overhead Hardened as of EOY 2021[(c)]	
	Outages per Year per Mile	% Improvement Compared to Zero CC	Outages per Year per Mile	% Improvement Compared to Zero CC	Outages per Year per Mile	% Improvement Compared to Zero CC
Zero CC	0.38	N/A	0.38	N/A	0.24	N/A
Partially CC (>0% and <80%)	0.22	41%	0.25	36%	0.17	28%
Mostly CC (>=80%)	0.11	69%	0.11	72%	0.07	70%

(a) Only considers outages from 2020 to 2022.
(b) Only considers outages from 2021 to 2022.
(c) Only considers outages in 2022.

The calculated outage reduction percentage (used as a measure for the recorded effectiveness) shows that CC sections experience approximately 28 to 70 percent fewer faults compared to bare conductor circuit segments.

The results in Table PG&E 22-11-2 above are preliminary due to the following:

- The analysis in Table PG&E 22-11-2 compares outages for locations that have CCs compared to locations with bare conductors. This analysis may over or under-represent effectiveness benefits because it does not capture the impact of localized environmental/weather conditions within HFRA.
- It is assumed that all distribution outages could potentially result in an ignition. It does not factor in if one type of outage is more or less likely to result in an ignition than other types of outages. However, there are several failure modes, such as tie-wire failure, which have a much lower likelihood of ignition compared to an outage due to a broken conductor.
- The outages in Partially CC and Mostly CC could have occurred on the sections of the line that are not covered, which cannot be validated due to lack of exact geospatial information for the outages.
- Approximately 30 percent of the hardened miles could not be directly linked to the appropriate upstream circuit segment due to the changes and dynamic nature of our system. Hence, they were not considered as part of the analysis.

Additionally, in 2023, as part of our ignition investigation process, we are incorporating additional reviews related to ignitions that occur on a CC line.

Below are some examples related to the effectiveness of CCs that we have observed:

Example 1 (Figure PG&E-22-11-1)

On May 10, 2021, a 125-foot ponderosa pine that was 55 feet away from a pole, failed approximately 40 feet above ground, severing the CC, causing a wiredown, and a subsequent CPUC-reportable ignition.

FIGURE PG&E-22-11-1:
COVERED CONDUCTOR EFFECTIVENESS – EXAMPLE 1

Affected Asset | Fallen Tree | Burn Scar | Severed Conductor

Example 2 (Figure PG&E-22-11-2)

On May 2, 2022, a 120-foot ponderosa pine that was being abated for previously reported structural concerns, fell on a CC line, severing it, starting a CPUC-reportable ignition.

FIGURE PG&E-22-11-2:
COVERED CONDUCTOR EFFECTIVENESS – EXAMPLE 2

These two incidents highlight some limitations concerning CC. In both incidents, there were VM inspections and CC deployed, but even with the combined mitigations, it still resulted in an ignition.

Example 3 (Figure PG&E-22-11-3)

On December 27, 2021, two CCs were supporting an entire tree. While there was no ignition an electrical outage did occur on the line.

FIGURE PG&E-22-11-3:
COVERED CONDUCTOR EFFECTIVENESS – EXAMPLE 3

Incorporation With Technology Alternatives

Please refer to the Joint IOU Study that describes technology alternatives and PG&E's collaborative efforts with other IOUs. PG&E will continue to participate in evaluating technology alternatives, sharing data, and effectiveness of alternative technologies as part of the joint IOU effort.

Changes in Cost and Impact Drivers

PG&E's unit costs for our Overhead System Hardening Program, which includes CC, have decreased between 2021 and 2022 as shown in Table PG&E- 22-11-3.

TABLE PG&E-22-11-3:
2022 COVERED CONDUCTOR SUMMARY

Cost Components	2021 Cost per Circuit Mile	2022 Cost per Circuit Mile
Labor (Internal)	$209,000	$129,931
Materials	$161,000	$150,783
Contractor	$470,000	$394,140
Overhead	$226,000	$140,298
Other	$6,000	$2,813
Financing Costs	$11,000	$7,733
Total	$1,083,000	$825,698

The costs in Table PG&E- 22-11-3 include the components for CC that are comparable with the other IOUs as part of the Joint IOU efforts. They do not include all cost components that make up our comprehensive Overhead System Hardening Program.

PG&E continues to rely on a combination of line removals, remote grid, and undergrounding as the primary system hardening effort due to its ability to reduce the most wildfire risk. We will continue to install CC in the appropriate locations.

ACI PG&E-22-12 – Covered Conductor Inspection and Maintenance

Description:

Pacific Gas and Electric Company (PG&E) lacks specific directives for inspection procedures and practice regarding Covered Conductor (CC) inspection and maintenance.

Required:

All electrical corporations (not including independent transmission operators) must work to share and determine best practices for inspecting and maintaining covered conductor, including either augmenting existing practices or developing new programs. This should be considered as a continuation of the CC effectiveness joint study established by Office of Energy Infrastructure Safety's (OEIS or Energy Safety) 2021 Wildfire Mitigation Plan (WMP) Action Statements. This study will continue to be utility-led, with the expectation for Energy Safety to be included as a participant. A report on progress on this continuation of the CC effectiveness joint study will be expected in the 2023 WMPs.

PG&E Response:

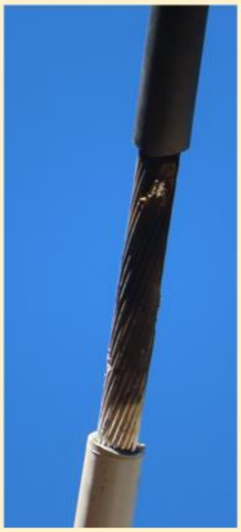
In 2023, PG&E updated our inspection checklist to include a specific question for identifying failure modes that are unique to CC based on the results from the CC testing and Subject Matter Expert discussions. The new inspection question is:

> "Primary CC has energized sections (such as rotated Kaddas covers, splices, connectors, flying bells) that are not covered or where the jacket has visible damage or signs of tracking."

In addition, the Overhead Inspection Job Aid (TD-2305M-JA02) for inspectors has been updated to include reference images of the type of damage inspectors should look to identify. Figure PG&E-22-12-1 below is an example of guidance given to the inspectors from the job aid.

FIGURE PG&E-22-12-1:
EXAMPLE OF DAMAGE FROM JOB AID TD-2305M JA02

Exposed Primary Covered Conductor Tree Wire, Burnt Conductor



At this Location: Tree Wire conductor exposed and burnt

Perform Minor Work: No

Write 3rd Party Notification: No

Write EC Notification: Yes

FDA= Tree Wire / Exposed / Repair

FDA= Conductor / Burnt / Repair

Priority: E Tag, 3-12 months depending on exposure

We will continue to use the findings from the Joint IOU CC effectiveness study to identify degradation mechanisms, threats, and hazards that need to be evaluated during the asset life cycle. Findings from this analysis will inform the inspection criteria and maintenance tag prioritization for CCs and will be incorporated into the 2024 distribution overhead (OH) inspection plan and inspection checklist as part of objective GH-03, which can be found in Section 8.1.1.1.

For additional information on the progress of the Joint IOU CC effectiveness study, please see PG&E's response to Areas for Continued Improvement (ACI) PG&E-22-11 and the Joint IOU CC effectiveness study included as an attachment in Appendix G.

ACI PG&E-22-13 – New Technologies Evaluation and Implementation

Description:

PG&E could benefit from cross-utility collaboration for new technology exploration and benchmarking.

Required:

All electrical corporations (not including independent transmission operators) must collaborate to evaluate the effectiveness of new technologies that support grid hardening and situational awareness such as Rapid Earth Fault Current Limiter and Distribution Fault Anticipation/Early Fault Detection, particularly in combination with other initiatives. Utilities must also share practices and evaluate implementation strategies for these new technologies. This should be considered as a continuation of the CC effectiveness joint study established by Energy Safety's 2021 WMP Action Statements. The scope of this study should now be expanded to cover grid hardening overall. The study will continue to be utility-led, with the expectation for Energy Safety to be included as a participant. A report on progress on this expansion of the CC effectiveness joint study will be expected in the 2023 WMPs.

PG&E Response:

Please refer to the section of the Joint IOU CC effectiveness study (Appendix G) on New Technologies Evaluation and Implementation for the response to this ACI.

ACI PG&E-22-14 – Decreased Transmission Hardening Targets

Description:

PG&E decreased its transmission hardening targets from 2021 to 2022 due to project lead time and delays from changing prioritization based on risk model output.

Required:

In its 2023 WMP, PG&E must show that it is setting transmission hardening targets based on risk and not decreasing targets solely based on project delays. If PG&E's updated risk model results in a lower number of transmission miles requiring hardening, PG&E must justify the decrease.

PG&E Response:

Wildfire mitigation selection (as described in Section 7.1.4) incorporates an approach across distribution, transmission and substation that aligns with overall utility risk. This influences prioritization and areas of focus for the organization.

PG&E is working to harden transmission assets and reduce wildfire risks through the multiple mitigation programs listed below. The decrease of the transmission hardening targets from 2021 to 2022 was specific to the Targeted Line Rebuild and Line Removal programs. We explain the decreased target in the Targeted Line Rebuild section below. Other programs either have steady progress or are newly initiated programs with targets.

In the Targeted Line Rebuild program, we identified major projects based on High Fire Threat District (HFTD) location, compliance obligations, and other factors before the Wildfire Transmission Risk Model (WTRM) was available. HFTD location was used to baseline the scope of this program. In 2022, PG&E conducted a risk, scope, and execution-stage assessment for each of the projects in progress to determine which should proceed and which could be put on hold. This effort allowed a quick transition to using the WTRM to select future projects.

The projects included in this program are identified based on WTRM and other asset health and performance risk considerations.

Other transmission hardening programs—Transmission Poles/Towers Replacements and Reinforcements and Transmission Tags—are prioritized using the WTRM and other asset health and performance risk considerations. The targets for these programs are not tracked separately but are an integral part of transmission tags as described in Section 8.1.7.1.

Targeted Line Rebuild (see Section 8.1.2.5)

Targeted lines traversing HFTD are selected for reconductoring. From there, these lines are fully assessed for all component asset health and compliance against current standards as well as electrical capacity needs. The project scope typically includes replacements of conductors, insulators, and structures. Asset replacements restore assets to new, up-to-standard, and typically incorporate a more robust design. These are large scale investments and work execution takes multiple years involving permitting, construction and clearance planning. While certain projects started years ago, the units are only counted when a project is released to operations. For these reasons, the number of miles completed may vary significantly from year to year. This work is part of target GH-05 in Section 8.1.1.2.

Dispersed Conductor Component (Splice) Hardening (see Section 8.1.2.5)

A conductor splice is considered a higher risk point of failure within a conductor span, due to factors such as corrosion, moisture intrusion, vibration, and workmanship variability. Certain type of splices, such as a twist splice, have shown to have higher risk of failure. We initiated a new program to install a shunt splice on top of an existing splice. This installation eliminates the splice as a single point of failure because failure of the original splice would not result in down conductor. Lines prioritized for this program are based on higher risk splice and wildfire consequences. Shunt splice installation is part of target GH-06 in Section 8.1.1.2.

Transmission Pole/Tower Replacements and Reinforcements (see Section 8.1.2.4)

There are multiple programs that improve the conditions of our structures, thus reducing failure and wildfire risks. One of these programs is the replacement of wood poles with steel poles. PG&E has replaced approximately 2,000 to 3,000 structures per year since 2019. This work is not tracked separately but is an integral part of the transmission tags described in Section 8.1.7.1.

Line Removal (see Section 8.1.2.9)

When we identify transmission lines that we confirm are no longer needed for operations they are prioritized for de-energization, grounding, and removal.

Transmission Tags (see Section 8.1.7.1)

Since the inception of the enhanced inspection program in 2019, a significant increase in the volume of repair tags has been created. PG&E has increased our efforts in addressing the maintenance backlog by performing approximately 250 percent the number of tags per year compared to work completed prior to 2019. A critical milestone will be reached in 2023 when we plan to complete the transmission tag backlog. Completing the maintenance repairs and replacements directly reduces failure and wildfire risks.

ACI PG&E-22-15 – Decreased Transmission/Distribution Sectionalization Device Targets

Description:

PG&E decreased its targets for installing additional sectionalization devices on both the distribution and transmission systems.

Required:

In its 2023 WMP, PG&E must either:

- *Adequately demonstrate and provide analysis performed to support the decreased targets (i.e., how the decreased target provides the same risk reduction benefit); OR*
- *Increase targets for sectionalization device installation for both the distribution and transmission levels. The targets should be set to provide appreciable benefits by decreasing the number of customers relying on each device.*

PG&E Response:

Transmission is not targeting additional sectionalizing devices in the 2023-2025 timeframe. To support this decision, we reviewed the current 10-year PSPS lookback. Of the 111 transmission lines in the 2022 10-year lookback, the lines either have already been sectionalized or do not presently need to be sectionalized. An example of a line that would not need to be sectionalized is a line that goes from one substation to another, with no junctions or tapped stations in between.

Automated distribution sectionalizing devices have been installed at strategic locations over the past 4 years, producing the greatest sectionalizing benefit given the 10-year lookback for PSPS event simulations. We have reached a point of diminishing returns based upon this analysis, where further investment would result in minimal customer benefits. In 2023, we are adjusting our distribution sectionalizing device program so that we will maximize reliability through our EPSS Program. Going forward, we will identify locations for sectionalizing with protective devices in smaller protective zones to improve the most reliability challenged circuit segments.

For both transmission and distribution, the 10-year lookback is updated annually and may result in adjustments to the program. Additionally, if we identify switch assets that need to be replaced during an inspection, we can upgrade them at that time.

ACI PG&E-22-16 – Progress and Updates on Undergrounding and Risk Prioritization

Description:

PG&E's undergrounding plan is not currently broken out by year past 2023.

Required:

In its 2023 WMP, PG&E must:

- *Provide an updated spreadsheet with the locations and mileage for undergrounding broken out by year from 2024 to 2026;*
- *Discuss how each project was prioritized based on risk and feasibility; and*
- *Provide an update on the progress PG&E has made thus far in meeting its undergrounding targets, both past and future, including any changes made in resources and availability of labor.*

PG&E Response:

In Section 8.1.2.2, Overview of the Activity, PG&E describes our approach for prioritizing undergrounding miles in HFTDs, including risk, feasibility, and current progress. In 2022, we completed 180 miles of undergrounding compared to a target of 175 miles and completed those miles below the targeted unit cost.

Please see PG&E's 2023-2026 Undergrounding Workplan,[209] which lists the planned undergrounding locations and mileage by year from 2023-2026.[210] To demonstrate the risk and feasibility of each project, the workplan includes the associated risk model used to identify projects in scope (either WDRM V2 or WDRM V3), as well as the Risk Rank,[211] Mean Risk,[212] Feasibility Score by Circuit Protection Zone (CPZ),[213] and HFTD Tier. The undergrounding projects included in the workplan are in any stage of

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[209] See Attachment 2023-03-27_PGE_2023_WMP _R1_Appendix D ACI PG&E-22-16_Atch01_CONF.

[210] Note, any miles included for 2022 reflect those projects that span multiple years from 2022 into 2023 and beyond. Not all 2022 completed miles are included in this workplan if those projects are not relevant to the 2023-2026 timeframe.

[211] Risk rank is a metric based on the results of the relevant risk model where circuit segments are ranked on a 1 to N basis, where 1 is the highest risk circuit segment, and N is the lowest risk.

[212] Mean risk is the summation of the total risk of all pixels (100 x 100-meter cell) linked to a circuit segment, divided by the total number of pixels. The total risk values are from System Hardening Wildfire Distribution Risk Model (WDRM) v3.

[213] The feasibility score is the cost multiplier indicating the difficulty of undergrounding the circuit segment based on presence of hard rock, water crossing, and gradient. The scale ranges from 1 to 3, with 3 being most challenging. The feasibility score is only available at the circuit segment level, and individual project feasibility may vary.

the review, planning and execution process. The information in this workplan is current as of January 3, 2023.

The total undergrounding miles included in the workplan exceed our annual targets as provided in Section 8.1.2.2, as well as the total 4-year target of 2,100 miles. We intentionally build-in additional miles, as compared to the annual targets, to account for unforeseen delays related to factors such as access, weather, permitting, land rights acquisition, materials or other constraints that may be experienced during the project lifecycle. Thus, some of the projects included in this workplan may not be completed in the 2023-2026 timeframe. Generally, PG&E will continue working on these projects until they can be completed in a future year.

The timing and mileage associated with an individual project can change as well due to project dependencies. Additionally, the mix of projects can change if new fire rebuild projects arise and they take precedence over certain planned projects. Finally, additional projects may be identified and added to the workplan going forward for potential completion in the 2023-2026 timeframe.

Project status and timelines will change as projects are further developed. All workplans are highly date-dependent and may not match a workplan provided previously or those that we provide in the future.

ACI PG&E-22-17 – Future Quantitative Targets to Reduce the Backlog of Repairs

Description:

PG&E's increased inspections (performed to exceed existing General Order [GO] requirements and better address wildfire risk) resulted in a backlog of repairs. While PG&E committed to backlog reduction targets, PG&E did not include quantitative targets for reducing its backlog past 2023.

Required Progress:

In its 2023 WMP, PG&E must provide quantitative targets for addressing repairs for infractions found during inspections, broken down by severity level of the finding, accounting for the entire backlog. Prioritization should be given for risk tags presenting the most ignition risk within the HFTDs/High Fire Risk Areas.

PG&E Response:

Please refer to the 2023 targets GM-02 and GM-03, which are presented in Section 8.1.1.2, as well as the associated narrative in Section 8.1.7 for a full description of how we are addressing this ACI.

ACI PG&E-22-18 – Retainment of Inspectors and Internal Workforce Development

Description:

PG&E does not currently have a defined plan to increase asset inspector employee retention, which may be affecting the quality of inspections being completed. PG&E also primarily relies on contractors to complete asset inspection work.

Required Progress:

In 2023, PG&E must:

- *Provide a plan to increase retention over time for trained and qualified inspectors; and*
- *Provide a plan for increasing and sustaining a consistent, year-over-year internal workforce that builds on existing experience and mentors new employees for asset inspections.*

PG&E Response:

PG&E has had a Distribution "Compliance Inspector" classification since 2003. We also have a dedicated Inspector workforce that consists of 151 authorized workers as of December 2022. Historically, we have been able to fill these positions and retain the Compliance Inspectors who are on staff.

PG&E relied on a high volume of contractor resources to complete overhead inspections over the last 3 years because of the increased volume of overhead inspections and increased inspection frequencies in HFTD areas. Until now, we have not had the opportunity to evaluate and "right size" our PG&E Inspector resources based on the volume of both overhead and underground work.

To resolve this, we plan to hire 100 additional employees between 2023 and 2025. We will benchmark with other utilities and work to create a new classification that can support the work that is needed. This increase in our headcount will enable us to develop experienced PG&E resources who know the geographic areas that they work in, who live and work in the communities that they support, and who can build trust and relationships in our hometowns.

Additionally, in 2023, we will be shifting field safety reassessments from System Inspections (SI) to Construction/Restoration, allowing our PG&E inspector resources to perform more inspections on time and further reduce our dependency on external resources. Additional headcount also will result in more leadership roles (Manager, Supervisor, Inspector Review Specialist) to support the new resources, which we anticipate will also drive an increase in performance.

However, we will still need to use some contractor inspector resources to ensure work is completed. To improve this process, in 2022, we entered into a 3-year vendor contract which helps us manage and monitor contractor performance and quality. It also helps us identify and retain the higher performing contract inspectors year over year, improving overall performance.

ACI PG&E-22-19 – Benchmarking With Other Utilities on Inspector Qualifications

Description:

PG&E may require qualifications of its asset inspectors that differ from those of other utilities, potentially inhibiting continued availability of qualified and competent inspectors.

Required Progress:

By its 2023 WMP, PG&E must benchmark its required qualifications of asset inspectors with the required qualifications of other utilities. Based on this benchmarking, in its 2023 WMP, PG&E must:

- *Provide a discussion of the differences in qualifications required by other utilities, as well as differences in the Quality Assurance/Quality Control (QA/QC) results of other utilities' asset inspections; and*
- *Analyze the pros and cons of adjusting its required qualifications to match those of other utilities and adjust its required qualifications as PG&E deems appropriate.*

PG&E Response:

As described in response to Maturity Survey Section 3.4.1, we hold regular benchmarking sessions with the other utilities as well as a continuing informal dialog and sharing of best practices. This includes actively seeking information from other utilities, actively sharing information with other utilities, and participating in benchmarking exercises to identify areas of improvement. We also plan to develop a standard process for testing applicability of best practices regarding the training and QA of asset personnel and to create procedures for sharing and receiving best practices and lessons learned in this area.

Additionally, PG&E reviewed the results from our benchmarking efforts with SCE and SDG&E related to classifications and qualifications of employees who perform inspections and patrols to determine potential areas for improvement. PG&E currently uses a journeyman lineman classification to perform all inspection and patrol activities, as does SDG&E. SCE, however, uses journeyman linemen for some activities but also uses a lower classification to perform other activities. In 2023, PG&E will continue our benchmarking with other utilities and—similar to SCE—is considering developing and using lower-level classifications to perform specific types of work. Classifications being considered include "Patrolman," who would perform patrol work, and an "Inspector" classification that would be qualified to perform both distribution and transmission inspections. Similarly, in the future, PG&E is looking to mirror our partners in California with a "360" inspection, where both drone and ground inspections can be completed simultaneously.

Thus, while we see the benefit of having a journeyman lineman perform all patrol and inspection activities at PG&E, we recognize that the skillset and experience of a journeyman may not be necessary for certain types of activities such as patrols. However, the creation of a new classification would also require a substantial overhaul of our training program, as all training and guidance is currently conducted with the understanding that the employees have journeyman lineman experience, which requires a different level of professional knowledge and experience than that of a lower classification, such as a patrolman. Regardless, we will continue to improve the quality of our inspection work, continue to benchmark with our peers, and continue to explore all options that may help us improve the quality of our work.

ACI PG&E-22-20 – Asset Inspection Drone Program Pilot

Description:

PG&E is using drones in a limited capacity within its aerial inspection program pilots.

Required Progress:

In its 2023 WMP, PG&E must:

- *Include testing and analysis results of drones for asset inspections as part of its aerial inspection pilot program;*
- *Report analysis from the pilot, including find rates across inspection types and effectiveness based on resource limitations and timing. PG&E must report find rates and effectiveness and also compare these between detailed asset inspections and climbing inspections; and*
- *Report on its 2022 expanded use of drones and other aerial technology for asset inspections based on findings from the pilot program.*

PG&E Response:

Introduction

Aerial inspections can provide visibility of overhead assets that may otherwise be challenging to obtain. This specific look at our assets may be especially helpful in detecting abnormal conditions on conductors, equipment, and the tops of poles. Drones and helicopters can also reach assets in remote areas more easily than inspectors on foot, capturing images that can later be inspected in a desktop review.

PG&E conducted very small aerial inspection pilots in 2020 and 2021 on distribution equipment. Based on promising results from these pilots, PG&E conducted an expanded pilot in 2022, inspecting roughly 6,500 structures and including three different methods of aerial inspection for distribution overhead structures: drone only; helicopter only; and drone plus inspector.

The 2022 pilot addressed the following questions:

- How effective are aerial inspections at detecting abnormal conditions on distribution overhead equipment?
- What types of conditions are better detected by ground versus aerial inspections?
- What is the rate at which aerial inspections can be performed and what execution considerations should PG&E consider when developing a distribution aerial inspection program?
- How do different aerial technologies and methods for inspection compare in terms of their outcomes on each of the questions above?

Methodology

Study Design

The 2022 pilot program planned scope consisted of 9,000 structures on 35 circuits across HFTD and non-HFTD areas. The scope was divided into three segments of equal size: 3,000 each of drone only, helicopter, and drone plus inspector.

PG&E-targeted problematic circuits already included in the 2022 ground inspection plan where aerial inspections would likely deliver the most benefit. Incorporating input from field supervisors, PG&E selected circuits with a history of high numbers of Category A tags, A tags on tie wires, locations with difficult terrain and near past wildfires, repeat ignitions related to overhead conductors, and circuits with notifications associated with insulators. The final structures selected were located in the North Valley, Yosemite, Sacramento, and Central Coast divisions.

Across inspection methods, we assigned 9,528 structures to be inspected to meet the goal of 9,000 structures, since we expected scope changes due to wildfires, drone, plus ground inspector scheduling issues, and out of scope structures like secondary and guy poles. These 9,528 structures were comprised of 2,106 structures in Non-HFTD, 5,820 structures in HFTD Tier 2, and 1,602 structures in HFTD Tier 3 areas.

Aerial inspections were conducted four to six weeks after detailed ground inspections were conducted on the same structures. The schedule for drone-only and helicopter-only inspections was developed based on the previously scheduled ground inspection. For the drone plus ground inspections, PG&E supplemented the planned GO 165 ground inspection by sending a drone operator out with the inspectors.

Inspection Methods

PG&E tested the following three aerial inspections methods:

- Drone Only: The drone only method entails a drone pilot alone in the field flying a drone and capturing eight to ten photos of all angles of a pole. The shot sheet focused on the top 2/3 of the pole. Within two to four weeks after the image capture, a remote desktop inspection is completed to identify abnormal conditions. The drone used in this method was a DJI Mavic 3. Drone only flights were conducted by pilots from approximately 7:00 a.m. to 5:00 p.m. Pacific Time.

- Helicopter Only: This method is the same as used for the drone only above, except the pictures were taken via helicopter and not drone. The helicopters took photos as they approached the structure offset from the centerline of the circuit by approximately 100 feet to provide a downward side view of the pole. Once the circuit run was completed, the helicopter flew back over the structures in the same manner from the other side. This flight path provided a good view of all quadrants of the pole from top to bottom. The helicopter used was a Eurocopter AS 350.

- Drone Plus Inspector: The drone plus inspector inspection augments a ground inspection with three to five pictures taken from the top of the pole downward. While in the field, inspectors viewed these images and recorded whether abnormal conditions reported were discovered because of the use of the photos. The same three to five photos were also inspected through a desktop inspection.

For each of these inspection types, customers were notified in advance of inspections through PG&E's standard process, including Interactive Voice Response and mailers.

Image Quality Assurance (IQA) and Emergency Conditions

The pilot included the development of an aerial QC process which was used to evaluate the preliminary image quality before a desktop inspection. The PG&E IQA team reviewed imagery for inspectability and any emergency tags (A tags). If an emergency tag was identified, the tag was escalated to an Inspection Review Specialist (IRS) for review. If the IRS concurred that it was a valid A tag, they created a document including the location as well as the description and pictures of the issue. The document was emailed to Dispatch, who addressed the A tag in accordance with PG&E's current A tag repair processes.

Desktop Inspections and Tag Creation

For drone-only and helicopter-only methods, inspections were conducted up to 48 days after image capture using iHawk, a vendor-provided platform. Desktop inspectors in the 2022 pilot were GO 165 Qualified Electrical Work inspectors.

The pilot used current business processes to create notifications. Inspectors created a new notification for conditions found if a structure had no open notifications. If a structure had an open notification, we added any new issues discovered to the same notification. Any duplicate tags (i.e., those already found by ground inspections) were cancelled. Finally, when inspectors or pilots noted inaccuracies in asset registry data during image capture or desktop inspections, they provided updates to the Geographic Information System team.

The pilot project relied on manual tag creation processes because automating the SAP notification process turned out to be a much more complex task than planned. Correctly cancelling duplicate finds and adding new finds to existing notifications required more complex programming than was initially anticipated.

Find Rate Calculation

Find rates are calculated by dividing the number of new notifications by the number of inspections performed. Note that more than one condition can be documented on a single notification and more than one notification can be assigned to a structure (based on different priority levels). To calculate find rates for ground vs. aerial comparisons, PG&E included only structures in the pilot that did not have open notifications in 2022 from prior years and where inspection results were reviewed by an IRS. Excluding structures with open notifications is necessary because the data structure limits us from easily seeing whether a finding is from 2022 or a previous year.

To compare findings between ground and aerial inspections, PG&E compared Facility Damage Actions (FDA) and tag priorities for the same structure. For a finding to be considered as found by both inspection methods, it had to be located on the same structure, have the same FDA and the same tag priority.

Results and Discussion

Inspection Methods

PG&E inspected a total of 6,514 structures as part of the aerial pilot out of the initial 9,528 structures that were planned. These 6,514 structures were comprised of 2,483 structures in Non-HFTD, 2,732 structures in HFTD Tier 2, and 1,299 structures in HFTD Tier 3.

PG&E inspected a total of 3,059 structures by the drone-only method, which delivered 100 percent of photos requested. Drones captured photos from all angles of the structure and desktop inspectors completed about 40 to 50 desktop inspections per day. The photo quality was excellent and permitted a thorough structure inspection. Customers provided incidental positive feedback in the field, appreciating the investment in new technology and methods.

PG&E inspected a total of 576 structures by helicopter-only method, which delivered 80 percent of photos requested. While PG&E originally intended to inspect closer to 3,000 structures by helicopter, we cancelled most helicopter inspections midway through the pilot. In prior small pilot projects, we were able to use helicopter photos. However, the vendor used in the 2022 pilot provided pictures that fell short of our quality expectations; the photo quality from helicopter inspections was poor and did not permit a thorough desktop inspection. PG&E assigned drones to capture photos of the structures missed by helicopters.

Furthermore, the helicopter inspections took photos from limited angles and missed approximately 20 percent of structures, largely due to tree obstruction. Helicopters were sometimes too large to maneuver to photograph dead-end poles and poles on steep slopes from all angles. Customers also shared incidental noise complaints in the field associated with the helicopters. The desktop inspectors each completed 40 to 50 desktop inspections per day of helicopter photos.

PG&E inspected a total of 2,879 structures by drone plus inspector method, which delivered 100 percent of photos requested. Adding drones to the detailed GO 165 inspection slowed the inspection to roughly 20 to 25 poles per day, which is slower than both the stand-alone ground inspection as well as the image capture rate for both drone-only and helicopter-only. The pilot project also faced challenges associated with trying to coordinate drone pilot schedules with ground inspection schedules. In the field, multiple inspectors noted that viewing conditions were not always ideal and camera glare was a challenge. This inspection method also demonstrated that drone pilot training needed improvement and that our picture requirements needed to be clarified.

Based on the results across the three inspection methods, PG&E concluded that the drone only method is the most promising for aerial inspections in the near-term. The value proposition for aerial inspections lies in detecting conditions that are challenging to see, especially those that are so severe as to create an immediate ignition or public safety risk. PG&E aims to get visibility on these conditions that we have previously been unable to detect as quickly as possible, and the drone-only methodology provides the best opportunity to do so. It was the methodology with the lowest unit cost and the ability to scale the most quickly since both image capture and desktop inspection can be done rapidly.

Helicopter-only inspections produced lower quality pictures at a higher unit cost. Due to the challenges associated with helicopter-only inspections, PG&E believes that helicopter-only is better used to supplement other aerial methods as needed or considered as a longer-term opportunity.

Drone plus inspector is a promising methodology but is also the most complex and challenging to scale quickly. Merging ground with aerial inspections into a single inspection would require investment in tools, training, and process development. Because far fewer structures could be completed each day under this inspection method, drone plus inspector would not permit PG&E to quickly find A and B-tag conditions. Driving the unit cost of a drone plus inspector inspection to reasonable levels would likely require training a considerable number of inspectors to become drone pilots. Furthermore, tag find rates and findings from this method also suggest that this approach still requires a remote desktop inspection for finding all conditions. These cost and execution hurdles need to be overcome before drone plus inspector could become a long-term solution.

Finally, through benchmarking efforts, PG&E learned that Southern California Edison Company (SCE) and San Diego Gas & Electric Company (SDG&E) also began their distribution aerial inspections using the drone-only method. SCE and SDG&E moved to drone plus inspector only after they completed several years of inspections in their systems with a drone-only method. This move was mainly due to a desire to have fewer field touches. SCE's current integrated method allows them to inspect roughly 6-8 structures a day.

Figure PG&E-22-20-1 below summarizes the outcomes from each of the methods used in the pilot program:

FIGURE PG&E-22-20-1:
RESULTS OF AERIAL PILOT PROJECT

	Drone-Only (Recommended for 2023)	Heli Only	Drone + Inspector
Photo Capture and Inspection Quality	All angles, high quality photos, very high find rates	Limited angles, missed ~20% structures, Average quality photos, medium find rates	All angles, high quality photos, high find rates, sub optimum field viewing, subject to glare
Speed	- 40 to 50 asset capture per day - 40 to 45 desktop inspections per day	- 40 to 45 desktop inspections per day	- 20 to 25 drone + field inspections per day per team - 40 to 45 desktop inspections per day
Unit Cost (pilot scale)	$186 per structure	$221 per structure	$311 per structure
Customer Impact / safety	Minimal negative customer impact	Minimal negative customer impact, some noise complaints	Minimal negative customer impact
Other			Scheduling challenges with drone pilots with ground inspectors

<u>Tag Find Rates</u>

For both ground and aerial inspections, tag find rates were generally high for the structures inspected in the pilot. Ground find rates for structures in the aerial pilot were generally higher than ground find rates across the service territory. The selection of problematic circuits and high tag density for inclusion in the pilot is the likely explanation for this trend. Table PG&E-22-20-1 below summarizes find rates for the pilot. Note that total find rate is based on structures (and so the percentages do not add up to the total). Below, PG&E discusses find rates for each aerial inspection method.

For drone-only inspections, find rates for A, B, and E tags were 1.2 percent, 3.0 percent, and 31.7 percent. Overall, drone-only inspections generally produced higher find rates (47 percent) than ground inspections of the same structures (31 percent). PG&E attributes the higher find rates for drone-only to the high-quality pictures taken by drone and the additional perspective from the air allows detection of conditions that are challenging to see from the ground. Furthermore, this pilot is the first aerial inspection of these structures, whereas ground inspections were completed at least once in the last five years for all the structures in the pilot and at most three years ago in HFTD, so conditions detectable by ground were likely already detected in previous inspections.

Drone produced comparable E tag find rates relative to ground inspections of the same structures, but slightly lower find rates for A and B tags. Pilot results underestimate the true ability of drone inspections to detect A tags due to the design of the study. Since aerial followed ground inspections of the same structure in all cases, A tags detected by ground inspections were addressed before aerial inspections took place, so there was no opportunity for aerial inspections to detect the A tag conditions found by ground.

A limited number of B tags were also addressed before the aerial inspection. None of the A tags found by any method of aerial inspection were identified by ground inspections.

There was a pronounced difference in ground and drone-only inspections for F tags, with drone-only inspections producing nearly four times as many F tags when inspecting the same structures. The other aerial inspection methods also yielded much higher F tag find rates relative to ground findings on the same structures. This finding is largely driven by the drone inspectors using different guidance when writing notifications for missing high voltage signs.

TABLE PG&E-22-20-1:
FIND RATES BY PRIORITY FOR GROUND AND AERIAL

	Ground (Structures Corresponding to Drone-Only Inspections)	**Drone-Only**	**Ground (Structures Corresponding Helicopter-Only Inspections)**	**Helicopter-Only**	**Drone Plus Inspector (Field)**	**Drone Plus Inspector (Desktop Inspection)**
Total Sample Size	3,059		576		2,879	
Find Rate Sample Size	2,580		549		2,650	
A	1.3%	1.2%	1.3%	0.4%	1.1%	1.3%
B	3.8%	3.0%	2.7%	1.1%	1.7%	1.6%
E	29.1%	31.7%	29.0%	24.2%	19.1%	35.2%
F	5.6%	20.7%	5.6%	18.8%	2.9%	25.1%
Overall	38.6%	47.1%	37.9%	40.1%	24.3%	51.1%

For helicopter-only inspections, find rates for A, B, and E tags were 0.4 percent, 1.1 percent, and 24.2 percent. Helicopter-only inspections had lower find rates than the ground inspections of the same structures for all three of these tag priorities. More specifically, helicopter-only inspections found less than half as many A and B tags as the ground inspections. These lower find rates from helicopter-only are likely attributable to lower image quality. As discussed above, helicopter inspections were halted due to images not being granular enough to permit detection of abnormal conditions.

PG&E separated tags created with the drone plus inspector method into tags generated in the field during the GO 165 ground inspection (including those from viewing images from the drone in the field) from tags created during the remote desktop inspection of the 3-5 photos. Both inspections produced similar find rates for A and B tags, roughly 1.2 percent and 1.6 percent. Similar with other inspection methods, the A tags found in the field (and a limited number of B tags) were already addressed by the time of the desktop inspection. In other words, all of the A tags found in desktop inspection were incremental to those found in the field, suggesting that not all A tag conditions visible by drone were necessarily identified by the inspector out in the field even though they had a drone. This may be related to sub-optimal field viewing conditions that many inspectors reported. Overall, findings from this method suggest that providing real-time drone images to the inspector in the field may not be sufficient for finding all conditions and that a remote desktop inspection may still be beneficial.

Finally, PG&E did not directly compare find rates from the aerial pilot to those from other key distribution inspection programs. In 2022, distribution Pole Test and Treat (PT&T) inspections had a 5.3 percent pole replacement find rate. Distribution infrared inspections had a 0.01 percent find rate for B tags and a 0.02 percent find rate for E tags. PG&E does not have a climbing inspection program for our distribution OH assets. While the overall find rates for ground and aerial in the pilot are much higher than these find rates of other programs, the find rates are not comparable since these inspections are designed to capture entirely different failure modes. PT&T is primarily designed to capture failure due to internal rot or shell degradation belowground, while infrared targets potentially damaged and/or faulty components that are not detectable solely by visual inspection methods such as ground or aerial.

Tag Findings

PG&E compared the findings from the drone-only inspections with findings from ground inspections of those same structures in the pilot. There was some overlap between findings, but most findings (92 percent) were found by either drone or ground, but not both. The percent overlap by priority was 0 percent for A tags, 10 percent for B tags, 8 percent for E tags, and 9 percent for F tags. These differences in findings largely reflect the differing vantage points of the two inspection methods. However, differences in how inspectors from ground compared to drone created notifications also drove some differences, with the same conditions being assessed as different priorities in some cases or as different FDAs. In other words, the overlap in findings is higher than the data indicates.

The most common and overlapping findings across both ground and drone-only inspections were missing high signs, a condition easily visible from both ground and air. Other common and overlapping findings across both inspection methods included improper conductor connections, loose hardware/framing, and decayed or rotten poles. The remaining findings show little to no overlap and are typically weighted heavily towards one of the two inspection methods. Table PG&E-22-20-2 below shows the top conditions identified in drone-only inspections and the corresponding structures inspected by ground.

Both ground and drone detected conductor and connector conditions, but drone-only generally detected more of them. Desktop review permits a close-up examination of tie wires, jumpers and jumper connections, splices, and conductors in the insulator shoes or on the very top of the insulators that are not visible from the ground. Dozens of drone tags revealed conductor damage (broken strands), broken tie wires, improper connections, tie wires in contact with the tops of arms (with tracking), melted tree wire insulation at connections, and loose clamps. Where both ground and drone detected tie wire conditions, the conditions were often rated more severe via aerial inspections, which had an improved and closer vantage point to view the condition.

TABLE PG&E-22-20-2:
TOP FDAs FOR DRONE ONLY AND CORRESPONDING GROUND INSPECTIONS
(ALL TAG PRIORITIES)

	FDA	Drone-Only Occurrence	Drone-Only FDAs percent of Total
1	High Sign-Missing-Install	377	22%
2	Conductor-Improper Connection-Adjust	363	21%
3	Pole-Broken/Damaged-Repair	225	13%
4	Hardware/Framing-Loose-Adjust	91	5%
5	Marking-Missing-Install	60	3%
6	Animal Mitigation-Mitigation Missing-Install	51	3%
7	Marking-Broken/Damaged-Replace	46	3%
8	Tie Wire-Loose-Replace	51	3%
9	Pole-Decayed/Rotten-Replace	52	3%
10	Conductor-Broken/Damaged-Repair	28	2%
11	Total FDA Population Reviewed	1,731	78%

	FDA	Ground Occurrence	Ground FDAs percent of Total
1	High Sign-Missing-Install	257	13%
2	Conductor-Improper Connection-Adjust	205	10%
3	Pole-Decayed/Rotten-Replace	165	8%
4	Connector-Incorrectly Installed-Replace	159	8%
5	Hardware/Framing-Loose-Adjust	79	4%
6	Pole-Broken/Damaged-Replace	77	4%
7	Guy-Loose-Adjust	67	3%
8	Crossarm-Decayed/Rotten-Replace	58	3%
9	Crossarm-Broken/Damaged-Replace	53	3%
10	Guy-Overgrown-Trim	47	2%
11	Total FDA Population Reviewed	1,999	58%

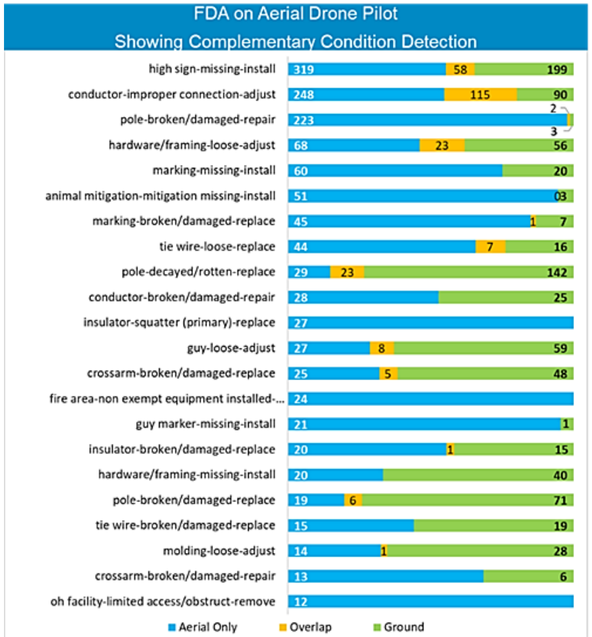
Drone inspections were able to detect many small hardware issues that are challenging or even impossible to see from the ground. Over half of the A and B tag findings from drone inspections come from the FDA hardware-framing-loose/adjust. Within the desktop inspections, the inspectors were able to clearly see small hardware such as cotter keys that are inserted into the pins that hold dead-end insulators to the crossarm at one end and to the conductor at the other end. Loose keys can quickly become missing keys, which could lead to conductors dropping to the ground.

Damaged and hollowed pole tops are another condition found by drone inspections that is challenging to observe from the ground. Some pole tops that look slightly rotted or damaged from the ground (jagged top) may be hollow down to more than 1 foot from the top. The aerial view can show if the shell of the pole at the through bolt is thin enough to be a risk of failure, a condition that could lead to the conductor dropping to the ground.

Ground inspections were better at detecting conditions at the bottom of the pole. These include vegetation issues as well as guy conditions at the ground level, including anchors, some of which must be unearthed for a thorough inspection.

Overall, the results indicate that ground and drone inspections are complementary in nature, with ground being able to better detect some conditions than drone, and vice versa. Figure PG&E-22-20-2 and Figure PG&E-22-20-3 below shows the overlap in conditions across different FDAs. Some of the patterns we see reflect the fact that not all FDAs were available for inspectors to select in iHawk. For example, the FDA “connector – incorrectly installed – replace” was not an option for the aerial inspectors and they used “conductor – improper connection – repair” in those cases. “Conductor – broken/damaged – replace” was also not an option. Some overlaps in condition detection are also underreported due to differences in choosing the action of “repair” vs. “replace” as part of an FDA. Some of these differences are training issues, but some are related to the visibility the aerial inspectors had of the issue. For example, woodpecker holes that were large, but shallow could be “pole-broken/damaged-repair,” but from the ground view the hole looked as though it could not be repaired, so ground inspectors may have selected “replace” instead.

FIGURE PG&E-22-20-2:
COMPLEMENTARY CONDITION DETECTION ACROSS DRONE ONLY AND CORRESPONDING GROUND CONDITIONS



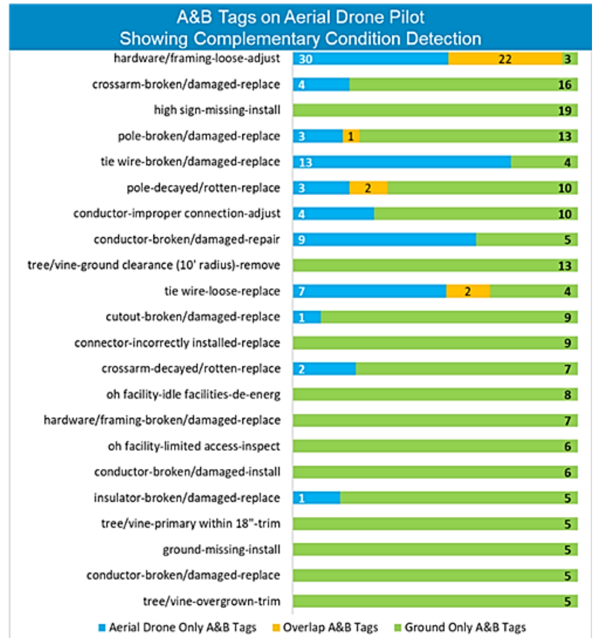
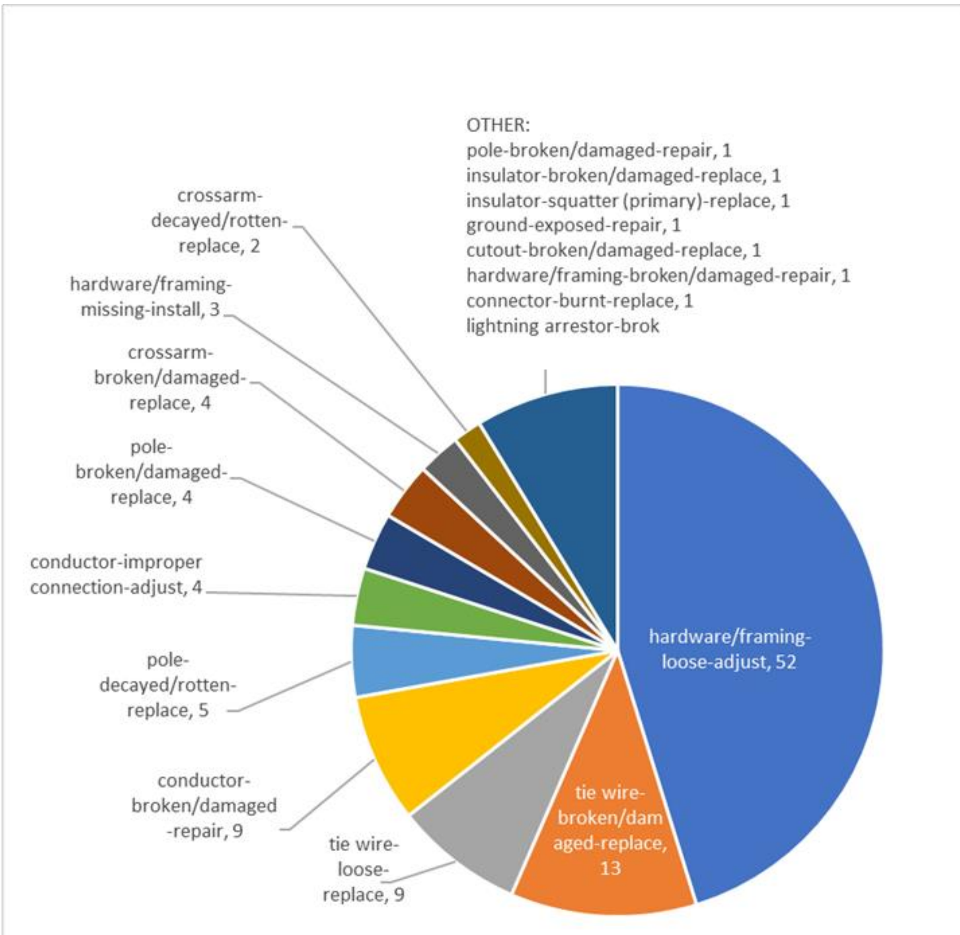


FIGURE PG&E-22-20-3:
FDAs FOR DRONE ONLY A AND B TAGS



Conclusions and Improvements for 2023

Based on the results of the pilot, PG&E concluded that there is significant value in using drone-only inspections to detect abnormal conditions on distribution assets. We reached this conclusion considering the costs and benefits of the drone-only inspection.

In this case, the benefit of the inspection is the ability to assess the risk of our OH assets from angles that are not normally accessible. The pilot results show that the drone-only inspections permit us to detect a larger variety of abnormal conditions on our OH assets, producing high tag find rates that will lead to corrective work to address the issues identified. The A tag find rate of over 1 percent was remarkable—the ability to detect and address emergency conditions on one out of every 100 structures was very compelling in deciding to further pursue distribution aerial inspections.

With respect to cost, the unit cost of drone-only inspections in the pilot ($186) was higher than that of detailed ground inspections ($112). PG&E expects that at scale, the cost of aerial inspections will reduce to become more comparable to the current cost of ground inspection. Based on these observations, PG&E concluded that there are benefits to continuing to explore the aerial inspection program. Benchmarking with other utilities also supports this conclusion; both SCE and SDG&E have pursued and grown their distribution aerial programs in recent years.

Preparing for 2023

PG&E used the results of this pilot to develop our pilot aerial inspection program for 2023. The pilot demonstrated that ground and aerial inspections are complementary in nature, with some conditions being more visible by ground and others by air. Given this finding, we decided to focus our near-term aerial inspection program on the top 1/3 of the structure, which can be more challenging to assess via ground inspections. Limiting the aerial inspections to a pole top inspection enables PG&E to cover more ground with aerial more quickly, keeping the focus on eliminating A and B tag conditions that are of immediate concern and not focusing on conditions that are better detected by a ground inspection.

With its high aerial tag find rates, the pilot program demonstrated that there is value in focusing this inspection on areas of high risk. This led to PG&E developing a 2023 aerial inspections strategy that continues to drive aerial inspections in locations where they will bring the most value—in the areas of PG&E's service territory where we are most concerned about catastrophic wildfires. Section 8.1.3.2 describes PG&E's strategy for identifying structures for aerial inspections in 2023.

The pilot demonstrated that we could implement aerial inspections on distribution at the scale of a few thousand. For drone-only inspections, PG&E had no safety issues and experienced minimal challenges in the areas of customer notification, vendor quality, photo capture, and the desktop inspection platform. However, the pilot demonstrated what areas of aerial inspections needed improvement before the program could be scaled:

1) Clarity on Photo Requirements: The pilot showed that PG&E needed to provide additional training for drone pilots and more clarity with respect to what pictures are required. For the 2023 effort, we have improved the drone pilot shot-sheet by including photos of the various pole framing types that show why we require additional pictures for certain framing types. Additionally, we are scheduling drone pilot training sessions to help the pilots understand our requirements and answer their questions before they begin work.

2) Automated Tag Creation Process: The pilot demonstrated that the manual process of tag creation was not scalable. We are building an automated process so that tags from desktop inspections are automatically created in SAP. For the aerial inspection program to scale, PG&E must be able to create new notifications or make changes to open notifications in real time. Additionally, we are building the processes and tools to execute a Field Safety Reassessment on open notifications.

3) Consistency in Tag Guidance: The pilot also showed that there was some inconsistency in how aerial desktop inspectors identified conditions relative to ground inspectors. To address this gap, PG&E consolidated guidance for desktop inspectors into the same OH Job Aid used by ground inspectors. The Job Aid was improved to include conditions and examples from aerial inspections, including pictures and a discussion of conditions on cotter keys, tie wires, and other equipment that may be better detected by aerial inspections. Additional FDAs will

also be added to iHawk to enable desktop inspectors to select the same conditions as ground inspectors.

As described in Section 8.1.3, PG&E will be using 2023 to expand the pilot aerial inspection program by focusing on drone-only inspections. We will use our learnings from 2023 to potentially set a specific WMP target in future years.

ACI PG&E-22-21 – Asset Inspections QA/QC

Description:

PG&E is falling behind on its asset inspection QA/QC goals and does not currently have goals for 2023.

Required Progress:

In its 2023 WMP, PG&E must:

- *Provide quantitative targets, including Acceptable Quality Levels (AQL), for asset inspection QA/QC for 2023 and 2024. The AQL target(s) for performance must be no less than 95 percent;*
- *Provide the results of its remaining 2022 asset inspection QA/QC;*
- *Discuss any additional changes made to its asset inspection program and/or QA/QC process based on continued lessons learned through the 2022 QA/QC program. This should include a list of specific failures and weak points that have contributed to PG&E's high QA/QC failure rates in 2022; and*
- *Provide a description of the progress made to reach its goals, including analysis of the impact of implementing each change to its QA/QC process.*

PG&E Response:

Table PG&E-22-21-1 below sets out the requested quantitative targets while Table PG&E-22-21-2 provides the results of the remaining 2022 asset inspection QA/QC.

**TABLE PG&E-22-21-1:
ASSET INSPECTION – 2022 AUDIT RESULTS AND 2023-2025 TARGET PASS RATES**

Inspection Type	Type of Audit	Audit Results 2022 (Critical Pass Rate)	Yearly Target Pass Rate for 2023-2025 (Critical Pass Rate)
Transmission	Desktop	92.3%	N/A
Transmission	Field	81.0%	N/A
Distribution	Desktop	85.5%	N/A
Distribution	Field	79.3%	N/A

TABLE PG&E-22-21-2:
QUALITY MANAGEMENT – 2022 QUALITY VERIFICATION TRANSMISSION AND DISTRIBUTION SI AUDIT RESULTS

	A	B	C	D
	Locations Audited	Locations w/ Critical Attribute Failure	Total Critical Attribute Failures	Pass Rate
Distribution	3,041	670	847	77.97%
Transmission	2,696	100	109	96.29%

- *Discuss any additional changes made to its asset inspection program and/or QA/QC process based on continued lessons learned through the 2022 QA/QC program. This should include a list of specific failures and weak points that have contributed to PG&E's high QA/QC failure rates in 2022*

We evaluate and make improvements to our Quality Control (QC) Program on a yearly basis. We focus on program efficiency, program effectiveness, stakeholder engagement, QC volume and sample size, and close out procedures. New programs are piloted and evaluated and, if approved, added to the QC program catalog.

The System Inspection Quality Control (SIQC) team is significantly increasing the number of Quality Reviews of inspections that SI completes. This will create a true quality management system, reduce risk, improve SI performance, and drive inspection improvements. For 2023, SIQC's desktop QC team will evaluate more completed inspections and Quality Verification (QV)/Quality Assurance (QA) will review a statistically valid sample of the SIQC team's work. The SIQC team will focus on the critical attributes defined by asset strategy. This will allow us to increase the number of reviews performed daily while focusing on ignition risk attributes.

QC discrepancies are documented in electronic QC Review Assessment forms. Dashboards are used to show quality trends and discrepancy data using pre-determined metrics. We use these QC dashboard results to provide training and coaching and to update training materials and procedures. The QC team provides content for the New Inspector Training Program that shows an overview of the top trends and findings from the previous program year. In addition, the QC team participates in the Inspect App updates, standards and job aid update working sessions, and provides feedback on gaps and continuous improvements opportunities.

The top three findings in Distribution in 2022, which demonstrate weak points or areas that can be improved, were:

1) Conductor has splices within 24 inches on insulator;

2) Loose Guy Wires; and

3) Pole Broke, damages, cracked, rotted, or decayed.

The top three findings in Transmission in 2022, demonstrating weak points or areas that can be improved, were

1) Loose Guy Wires;

2) Pole top has damage or split top; and

3) Structure has bird, animal, or insect damage.

To address problems, we developed different criteria for addressing QC findings including:

- Revising policies, standards, procedures, checklists, and tools and providing training related to the revisions;
- The QC leadership team holds meetings to discuss the assessment results and trends;
- Sharing dashboards, charts and other visual management aids showing trends, metrics, and highlights from the QC process; and
- Using the QC data to drive improvements.

On a quarterly basis as part of the close-out procedures QC will submit a Corrective Action Plan containing:

- A summary of findings summary, trending metrics, and overall program results; and
- Tasks, strategies and corrective actions required to address the findings.

Systems inspection quality verification will focus on validation of the inspections performed by SIQC, to ensure effectiveness of QC and build additional levels of defense against failures.

- *Provide a description of the progress made to reach its goals, including analysis of the impact of implementing each change to its QA/QC process.*

There are three layers of defense for the 2023 programs: QC, QV, and QA.

SIQV is now integrated into the QC department and will follow the same guidelines and processes as QC. Building the program in the same department allows for standardization and consistency for quality reviews of inspections. QC and QV have clearly defined objectives, scopes of work, and an execution plan. This allows for consistency and a frequent exchange of information ensuring that all findings are addressed.

QA/QV will review a statistically valid sample of the SIQC team’s work.

QA focuses on ensuring compliance discrepancies resulting from completed QC and QV assessments are integrated into improvement plans. QA also updates standards, procedures, and training. QA assess trends and the root causes of compliance issues and performs process audits.

Establishing a quality vertical that includes layers of defense is an improvement compared to having than multiple, duplicative layers that do provide additional control or assurance of quality.

ACI PG&E-22-22 – Progress on Meeting Asset Inspection Regulatory Requirements

Description:

PG&E is not meeting GO requirements; it has thousands of overdue work tags.

Required Progress:

PG&E must come into compliance with and eliminate its maintenance backlog pursuant to the relevant, overdue GO work order backlog requirements by the end of 2023. In its 2023 WMP, PG&E must:

- *Provide its resource plan describing how it will progress on closing outstanding and overdue work orders in the HFTD to eventually reach a functional capability whereby more work orders are being closed than are being opened;*
- *Provide an update of its progress on addressing remaining work tags in 2022, including the number of work tags opened and closed per quarter;*
- *Provide a remedial plan to address its full maintenance backlog including GO backlogs as soon as feasible; and*
- *By the end of 2023, develop a plan detailing how PG&E will clear the GO repair backlog no later than the end of the 2023-2025 WMP cycle and demonstrating capability to maintain its repair cycle within GO requirements. PG&E must include this plan in its WMP Update submitted in 2024.*

PG&E Response:

PG&E interprets the ACI header "Progress on Meeting Asset Inspection Regulatory Requirements" to refer instead to maintenance requirements, given the ACI description. Please refer to the 2023 targets GM-02 and GM-03, which are presented in Section 8.1.1.2, and to the associated narrative in Section 8.1.7 for a complete description of how we are addressing this ACI.

ACI PG&E-22-23 – Reduce Necessity for the Utility Defensible Space Program

Description:

PG&E clears a 50-foot horizontal radial distance around some poles in the HFTD as part of its Utility Defensible Space (UDS) Program. While Energy Safety believes UDS is effective, Energy Safety does not consider this activity to be a long-term solution.

Required Progress:

In its 2023 WMP, PG&E must:

- *Report on any progress made to reduce the need for the UDS Program; and*
- *Provide a plan for achieving progress that extends through the 2023-2025 WMP cycle.*

PG&E Response:

PG&E developed a UDS Program in 2021 that addresses reduction or adjustment of live fuels. UDS expands vegetation clearance around certain poles to extend the firebreak. UDS is not used as extensively as pole clearing but is based on a risk informed prioritization and has a more limited scope.

Starting in 2023 the program will begin to incorporate maintenance of work completed in newly developed Areas of Concern where the work overlaps with the pole clearing program. The UDS Program will also continue to target new populations with annually updated tranches that prioritize the work targeted for execution. This work and maintenance will target both transmission and distribution assets to supplement the work completed by the pole clearing program at higher risk assets and locations.

ACI PG&E-22-24 – Progression of Vegetation Management Maturity

Description:

In response to RN-PG&E-22-09, Pacific Gas and Electric Company (PG&E) identified several initial steps to mature in certain capabilities in its vegetation management (VM) program.

Required Progress:

In its 2023 Wildfire Mitigation Plan (WMP), PG&E must report on its progress in implementing its initial steps to increase the maturity of its VM program including any resulting plans and timelines.

PG&E Response:

To improve VM program maturity PG&E has taken actions to meet RN-PG&E-22-09 commitments and is taking additional actions that will enhance or improve specific elements starting in 2023.

Actions Specific to RN-PG&E-22-09

PG&E developed Areas of Concerns in 2022. This was a multiple phase effort involving cross functional teams to evaluate 47 counties within our service territory. Evaluations used numerous available datasets, including but not limited to, seasonal outages, Enhanced Powerline Safety Settings (EPSS) outages, ignitions, Public Safety Power Shutoff (PSPS) history, PSPS damage, and local knowledge to create polygons that encompass overhead (OH) circuits that we will target for focused VM efforts beginning in 2023.

Focused Tree Inspections: PG&E is developing AOCs to better focus VM efforts to address high risk areas that have experienced higher volumes of vegetation damage during PSPS events, outages, and/or ignitions. We have conducted a county-by-county review with regional SMEs and used this information to develop polygons where focused vegetation inspections can be evaluated to determine appropriate counties to prioritize pilot(s). Focused Tree Inspection plans will be piloted in at least one area. The pilot will develop and implement guidelines that inform inspections

Pilot activities are scheduled to begin in Quarter 2, 2023 and are referred to as the Focused Tree Inspection program.

We describe the Focused Tree Inspection program in Section 8.2.3.4.

ACI PG&E-22-25 – External Engagement for Vegetation Management

Description:

PG&E has created a Constraints Resolution Team and expanded access to "ProjectWise" to address VM constraints. Nevertheless, PG&E must continue to make efforts to decrease constrained miles for VM programs.

Required Progress:

In its 2023 WMP, PG&E must report on how it is addressing and reducing the number of constrained miles for VM programs, including metrics. Additionally, PG&E must consider setting internal targets for the Constraints Resolution Team to demonstrate its success rate and report on these targets in its 2023 WMP. PG&E must also consider creating a "right tree right place" program: offering tree replacements at no cost to customers may reduce customer refusal constraints.[214]

PG&E Response:

PG&E VM can be constrained by environmental delays, individual customer issues, permitting delays/restrictions or operational holds, weather conditions, active wildfire, and accessibility into an area where inspections are required. To address constraints, we work through our VM processes to resolve the roadblock and execute the work.

In 2023, VM plans to start the process of centralizing constraints resolution. As part of the build out of the centralized constraints team, three major categories will be addressed: customer constraints, environmental constraints (including internal PG&E procedures required to perform work) and permitting constraints (including both Land and Environmental permits). PG&E will consider creating a "right tree-right place" program, as part of the centralize Constraints Resolution process.

For each major constraint category, the constraints team will partner with Operations to build a process for addressing each constraint type, implement the new process, and create metrics to track each constraint type. Reporting will track total constraints by type and the time it takes to resolve a constraint after it has been identified.

[214] Final Decision on PG&E's WMP 2022 Update (Nov. 10, 2022), p. 181.

ACI PG&E-22-26 – Auditing of Internal Pre-Inspectors

Description:

PG&E has hired 108 internal pre-inspectors. PG&E's Quality Assurance/Quality Control (QA/QV) scope currently does not apply to internal pre-inspectors.

Required Progress:

By the time PG&E submits its 2023 WMP all pre-inspectors must be subject to the QA/QV.

PG&E Response:

The field quality control group performs individual observations/assessments of the pre-inspection population.

For the 2023 Vegetation Management programs that use pre-inspectors, the QA/QC sample will be taken from work performed by contractor and internal pre-inspectors. The procedures that the QA/QV team follows will be revised in 2023. PG&E anticipates that the updated procedures will be complete by the end of the second quarter of 2023.

ACI PG&E-22-27 – Vegetation Management Wildfire Inspection Guide – Stakeholder Engagement

Description:

PG&E is developing a VM Wildfire Inspection Guide to assess hazard trees in post-fire situations.

Required Progress:

PG&E must engage with Energy Safety, California Department of Forestry and Fire Protection (CAL FIRE), the Wildfire Safety Advisory Board, and stakeholders to receive feedback on the guide. In its 2023 WMP, PG&E must attach the finalized guide, provide a summary of stakeholder input, and report on any input given by stakeholders that was integrated into the guide.

PG&E Response:

PG&E's VM Wildfire Inspection Guide served as an interim guidance document through 2022. This interim document is being replaced by a PG&E Standard that will published in early 2023 and a supporting procedure to be developed in Quarter 1 2023.

PG&E will engage with Energy Safety, CAL FIRE, the Wildfire Safety Advisory Board, and other stakeholders to receive feedback on the Standard in Quarter 1 2023. Feedback will inform the procedure document which will follow similar vetting and evaluation from external stakeholders prior to preparing for fire season in 2023.

ACI PG&E-22-28 – Progression of Effectiveness of Enhanced Clearances Joint Study

Description:

The 2021 Action Statements required the large Investor-Owned Utilities (IOU) to conduct a study assessing the effectiveness of enhanced clearances. Progress has been made in the study; however, the study must continue to progress.

Required Progress:

By the submission of the 2023 WMPs, PG&E, along with Southern California Edison Company (SCE) and San Diego Gas & Electric Company (SDG&E), must (1) standardize the data collection process for the cross utility database of tree-caused risk events, (2) determine where and in what form the database will exist, (3) examine, to the best of their ability, whether the correlation between enhanced clearances and the lower number of tree caused outage events may be attributable to other factors beyond clearances, such as the management of hazard trees and the installation of covered conductor. Energy Safety expects the large IOUs to make incremental progress and update their analyses with each WMP submission through at least 2025.

PG&E Response:

The utilities have prepared a joint response to this Area for Continued Improvement.

SDG&E, PG&E, and SCE (jointly, IOUs) have continued to collaborate on the vegetation clearance study. Bi-weekly meetings occurred throughout 2022 with attendees from the IOUs and Energy Safety attending.

The IOUs are focused on addressing the required progress of this study, which include:

- Standardize the data collection process for the cross-utility database of tree-caused risk events;
- Determine where and in what form the database will exist; and
- Examine, to the best of our ability, whether correlation between enhanced clearances and the lower number of tree-caused outage events may be attributable to other factors beyond clearances, such as the management of hazard trees and the installation of covered conductor.

To most effectively achieve the objectives of the study, the IOUs chose to hire a third-party to establish the data collection standards, create the cross-utility database, and study the relationship between enhanced vegetation clearances and tree-caused risk events. A third-party vendor will provide both experience in data analysis and an independent review of the data and conclusions.

To select a qualified vendor for this multi-year engagement the IOUs nominated potential bidders for the work, and SDG&E led a Request for Information (RFI) effort that was sent to eight different vendors. The RFI was distributed in February, with responses due back in early March. After reviewing and scoring the information received from the vendors, three were then invited to participate in a Request for Proposal (RFP). The documentation for the RFP was prepared and distributed to the vendors in early June and responses were received in July. The RFP materials were scored, and negotiations began with the selected vendor in August. The contract was completed in October and the vendor began attending the joint IOU meetings and beginning data collection for the study. Progress on each of the required areas is provided below:

1. Standardize the Data Collection Process for the Cross-Utility Database of Tree-Caused Risk Events:

   The Electric Power Research Institute (EPRI) research team is implementing the first phase of the study: Database Evaluation. The first step has been for EPRI to request a sample set of data from each of the participating IOUs. This data includes information from relevant vegetation, outage, Geographic Information System (GIS), weather, and related data sets. The data samples are currently under review and a meeting with the research team and the IOUs is planned for Q1 of 2023 to discuss the data fields. After this discussion, a larger sample of data will be requested from each of the IOUs, including relevant metadata, and historical data. These will be combined into a database and jointly evaluated. The EPRI team will consider how best to combine the three separate groups of data into a single database. This will begin the second phase of the study: Database Development (that will exist on the EPRI Server). The three phases are described in more detail below.

2. Determine Where and In What Form the Database Will Exist

   The database will exist on the EPRI Server, and outage data will be pushed to EPRI at a cadence determined over the course of the project, likely weekly. Vegetation, weather, GIS, and other datasets will also be pushed to the database at selected, regular intervals. The outage data will include outages that are not vegetation related. EPRI will query the freeform notes to extract possible tree related outages that were mis-coded. EPRI will examine and put the utility data into a common format and create a new database from the combined utility data. This data will be accessible for queries by the participants. If all the participants agree, the data can also be available for downloading, and can be made anonymous by the providing utility prior to transfer.

3. Examine, to the best of our ability, whether correlation between enhanced clearances and the lower number of tree-caused outage events may be attributable to other factors beyond clearances, such as the management of hazard trees and the installation of covered conductor.

   This will be done by first examining a selection of each IOU’s databases including weather, vegetation management, GIS, OMS, and other related databases. The review will first include a review of the datasets, the frequency of collection, the quality of the data, the confidence in the data, historical data available from each IOU, the metadata, variables, definitions. Each utility will also identify a data steward. Using this information from the sample selection, and a second request for larger dataset, we will create a data dictionary. After reviewing the samples of each company, and during the discussions described below, we will develop the joint database. The fields and coding systems in the joint database will be designed with the utilities and will leverage the vendor's prior experience on similar projects. The EPRI Data Science Platform will be able to integrate data of various formats and types, facilitating the data analysis described below.

Future plans for the study include creating the joint database across the three utilities to establish uniform data collection standards, focus on tree-caused risk events, incorporate both biotic and abiotic factors, and assess the effectiveness of enhanced clearances. Once the database is created, there is a great opportunity for researchers and practitioners to gain deep insights into the causes of ignition events and the potential vegetation management options to mitigate them. The study has the potential to address short and long-term research needs in California, where wildfire risk is expected to increase.

The following steps will be implemented between January 2023 and June 2024.

1. Database Evaluation:

    a. First, a sample of each IOU's database will be evaluated, recognizing that each IOU's database has some common fields and other fields that are not aligned. Then a larger section of the data will be evaluated. This will be to review existing data and guidelines for data collection and determine if the current structures allow the key research questions for this project to be addressed. To that end, and to ensure that the data can help us answer our key questions, we plan to have immersive discussions with each IOU's respective vegetation management and outage management teams to better understand what data is currently captured and to evaluate the level of quality and certainty of data contained in the database fields. This purpose of the immersive discussions is to understand the current database structures used by each utility, the method of recording data, the type of historical records available, the definitions of specific tree-pruning activities, the differences in the outage management systems (OMS), and other information that may vary by utility.

    b. The research team and utility Subject-Matter Experts from each of the three IOUs will attend a group workshop. This is tentatively scheduled for February 6-7. During this meeting we will discuss the key question raised at the individual meetings and discuss the possibility of modifying outage cause codes to best capture the information needed to perform a meaningful study, including sharing ideas regarding additional data fields. As a team (research team and utility SMEs) we will decide on the design of a consolidated database structure to be used moving forward.

    c. Third, once outage cause codes are determined, a survey/coding workshop will be held describing scenarios that should be coded. This survey will be given to all employees that input cause codes in the OMS. While the survey will capture the initial inputs, the survey will also present the user with the desired coding based upon the decisions made in the group workshop.

2. Database Development:

EPRI will base the database development on previous experience with cross utility databases such as the industry wide databases for Transmission and Distribution asset performance, inspections, and maintenance. Before defining the final database structure, we will adopt a phased approach. Initially we will investigate each utility's data individually. We then look at the lessons learned to assess the broader applicability. At that stage, we begin developing a cross utility database and design the criteria around how the common database is set up and populated, as well as the data management lifecycle criteria.

3 Data Analysis:

a. In addition to a single, unified database structure, and having the data that allows IOUs to understand every vegetation contact with the lines, there is a need to drill down to understand vegetation treatments and their effectiveness. Assuming adequate history on circuits that have data before and after enhanced clearance work was performed, we would conduct statistically valid analyses on that group of circuits. The general objective of the data analysis would be to understand the effect of enhanced vegetation clearances on outage performance. The results would likely lead to other analyses and comparison with other treatment approaches depending on weather conditions. Depending on the type of data received, its granularity, the temporal scale, length of time that enhanced vegetation management has been implemented in the circuits, and how many variations the utility has used, there are many different options for analysis. For example, if the circuit characteristics and approaches are substantially different from one another (circuit to circuit or utility to utility) a self-benchmarking or baseline extrapolation might be possible if sufficient historical data is also provided. Other analyses will be determined based on the available data.

b. EPRI will share the results of Data Analysis in a technical memo which will include data, graphs, charts, and narrative text. This information can be used to share results with joint IOU stakeholders, including agencies, and the general public, regarding results of the analysis and any insights regarding the potential links between enhanced vegetation clearing, outages, and ignition risk.

Separate from the joint IOU database study on enhanced clearances, each of the large IOUs have completed work to understand the effectiveness of enhanced clearances within their respective service territories. Details on these efforts are described below.

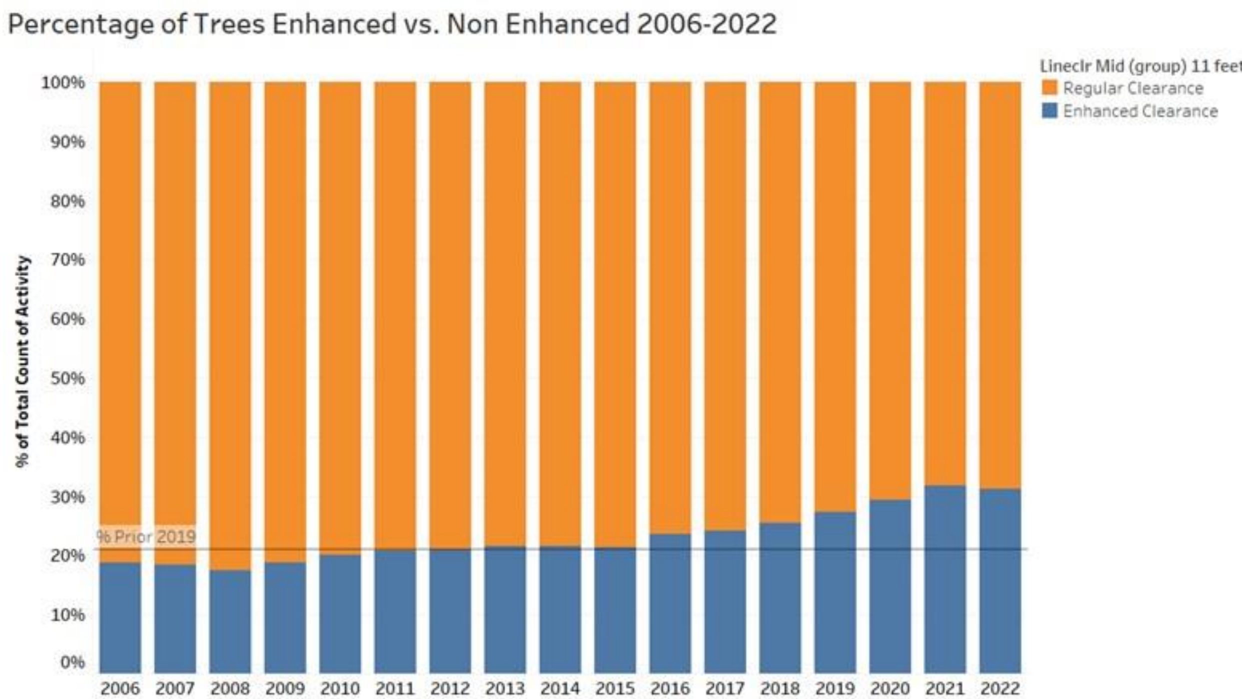
SDG&E

SDG&E has implemented several initiatives within its Vegetation Management program to reduce power outages and mitigate the risk of wildfire. These initiatives include covered conductor, undergrounding, enhanced inspection processes, and enhanced line clearance. To assess the impact of the Enhanced Clearance Vegetation Management program, which was launched in 2019, we conducted an analysis. Our goal was to understand the effectiveness of this program in reducing outages and potential wildfire.

According to the California Public Utilities Commission General Order (GO) 95, Rule 35, distribution voltage lines in California must have a minimum clearance of 18 inches. In the High Fire Threat District (HFTD) region of the state, the minimum clearance is 4 feet for distribution lines. For the purposes of this analysis, “enhanced clearance” refers to trees that were trimmed to a height above 11 feet. In 2019, SDG&E increased the percentage of trees managed at enhanced clearance distances (11 feet or higher) to 25 percent of its inventory and saw a reduction in power outages. The graph (Figure PG&E-22-28-1 and Figure PG&E-22-28-2) below illustrates the percentage of inventory trees that were managed at enhanced clearance distances versus not enhanced from 2006 to 2022.

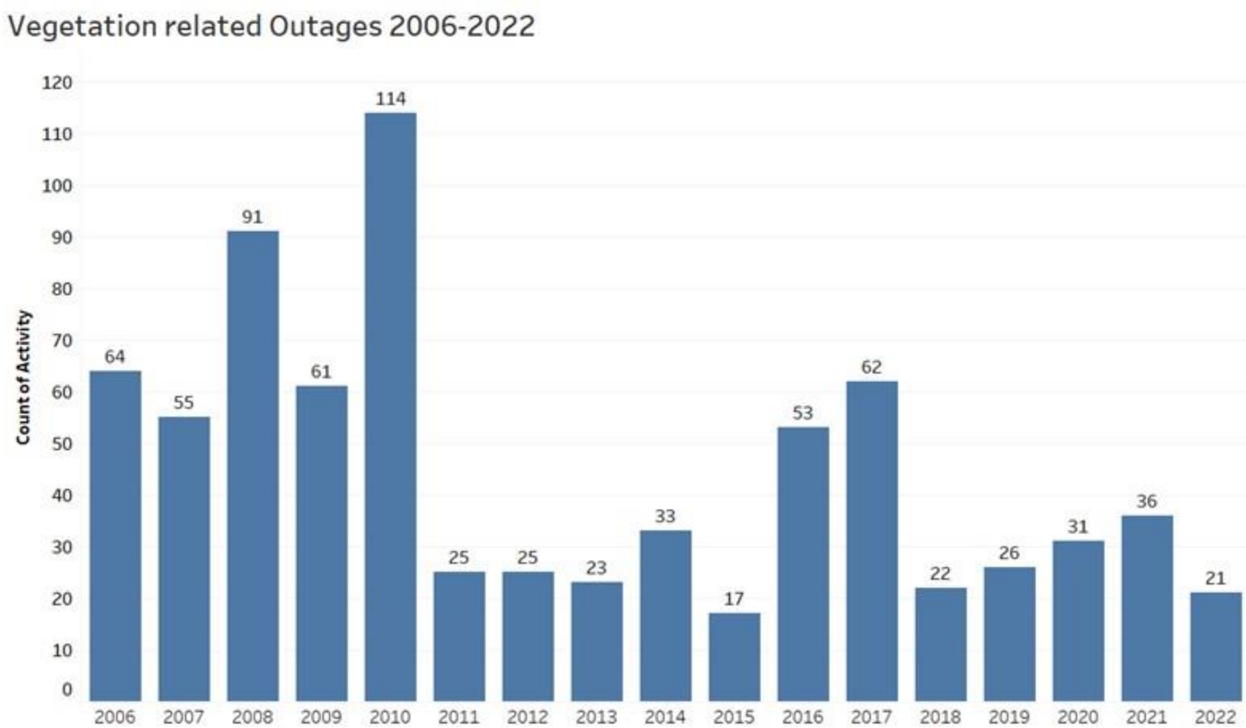
Distribution of Tree Inventory Line Clearance Distance

FIGURE PG&E-22-28-1:
SDG&E – percent OF TREES ENHANCED VS. NON-ENHANCED 2006-2022



Historical Vegetation Related Outage Count

FIGURE PG&E-22-28-2:
SDG&E – VEGETATION-RELATED OUTAGES 2006-2022



To understand its outage reduction over recent years, SDG&E analyzed historical data. When comparing the years 2019-2022 to 2014-2018, SDG&E observed approximately a 20 percent improvement in outages (Figure PG&E-22-28-3).

FIGURE PG&E-22-28-3:
SDG&E – OUTAGE COMPARISON

Year	Group	Count of FACILITYIDs	Outage Count	Outage Rate (Outage Count/Count of FACILITYIDs)	% of FACILITYIDs less or equal to 11 feet	% of FACILITYIDs greater than 11 feet	Avg % of FACILITYIDs greater than 11 feet	% Change	Average Outage Count	Outage Improvement (count)	Outage Improvement (% change)	Average Outage Rate	Outage Rate Improvement	Outage Rate Improvement (% change)
2014	Prior EVM (14-18)	393,217	33	0.008%	78.4%	21.6%								
2015	Prior EVM (14-18)	388,903	17	0.004%	78.6%	21.4%								
2016	Prior EVM (14-18)	383,351	53	0.014%	76.3%	23.7%								
2017	Prior EVM (14-18)	379,431	62	0.016%	75.8%	24.2%								
2018	Prior EVM (14-18)	381,170	22	0.006%	74.6%	25.4%	23.2%		37.4			0.010%		
2019	EVM (19-YTD 22)	377,554	26	0.007%	72.7%	27.3%								
2020	EVM (19-YTD 22)	377,919	31	0.008%	70.7%	29.3%								
2021	EVM (19-YTD 22)	384,613	36	0.009%	68.2%	31.9%								
2022	EVM (19-YTD 22)	*372,472*	*24*	*0.006%*	*68.8%*	*31.2%*	29.9%	6.67%	29.3	8	21.8%	0.008%	0.0020%	20.7%

To determine the contribution of the enhanced clearance initiative to the observed improvement in outages, we employed a machine learning model (logistic regression) to analyze the relationship between line clearance distance and the probability of tree-caused power outages. The logistic regression model considered various variables that may impact outage probability, and we conducted a sensitivity analysis to examine the effect of line clearance distance on outages while holding other factors constant.

SDG&E analyzed all activities from 2014 to 2022 to understand the relationship between line clearance distance and the probability of tree-caused power outages. We linked each outage event to its corresponding inspection or trim activity to determine the most recent line clearance distance before the outage occurred. The variable "outage" served as the flag variable that was predicted in the model.

The following features were included in the model:

- Species;
- Line Clearance Distance;
- Enhanced Clearance (yes or no);
- Tree Height; and
- Diameter at Breast Height.

To evaluate the performance of the model, the entire dataset was split into training and test data sets. The training set was used to build the model, and the test set was used to evaluate the model's performance on unseen data. Once we understood the model's performance, we altered the line clearance distance in the sensitivity analysis to understand its effect on the predicted probability of outages for each activity.

The sensitivity analysis reduced the line clearance distance of all activities with a line clearance distance above 11 feet (enhanced clearance level) to 11 feet. We then reran these activities through the model using the same threshold value to make predictions. We assumed that the new distribution of activities would have the same performance distribution as the actual data, allowing us to determine the number of outages that were potentially prevented for these trees.

By altering the line clearance distance value, but holding other factors constant, we were able to evaluate the impact of line clearance on tree-related outages. Our results revealed that reducing line clearance from enhanced levels (>11 ft) to regular levels (11 ft) led to an increase in the number of predicted tree-caused outages. Specifically, the model predicted a reduction in tree-related outages by approximately 12 percent attributed to enhanced clearances.

PG&E

PG&E launched the EVM program in response to changing environmental conditions and based on our best view of risk mitigation at the time. Since launching EVM in 2019, PG&E's wildfire capabilities have continued to evolve and mature; we now have solutions that provide more effective and efficient wildfire risk reduction such as PSPS, EPSS, System Hardening and other Operational Mitigations. We are also evaluating additional Operational Mitigations, including partial voltage detection, downed conductor detection, and breakaway connectors, each of which will further reduce the risk of catastrophic wildfires. The data below shows a slight decline in the 2022 non-Major Event Days (MED) Outages performance compared to the 3-Year Average.

The good measure is to compare the outages reduction because ignitions are impacted due to other wildfire reduction mitigation.

Data in the table below is not Normalized for Non-MED Outages (i.e., there are more non-MED in 2022 compared to 2021).

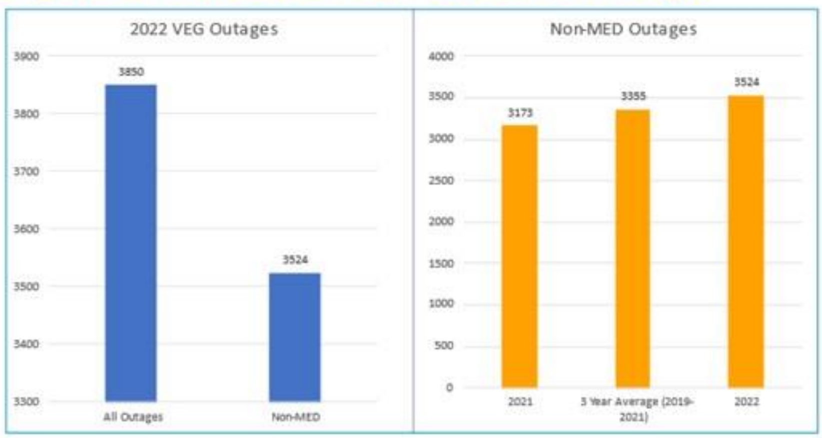
FIGURE PG&E-22-28-4:
PG&E - 2022 VEGETATION OUTAGES COMPARED WITH 2021 AND 3-YEAR AVERAGE

Vegetation Outages Review

2022 VEG Outages Compared with 2021 and 3-Year Average

Year	All Outages	Non-MED Outages
2021	7520	3173
3 Year Average (2019-2021)	6567	3355
2022	3850	3524

- 2022 Performance compared to the 3 Year Average and 2021 has slightly declined/slipped.
- There were fewer Major Event Days in 2022.



Internal

FIGURE-22-28-5:
PG&E – VEGETATION MANAGEMENT NON-MED OUTAGE RUNNING TOTAL DASHBOARD

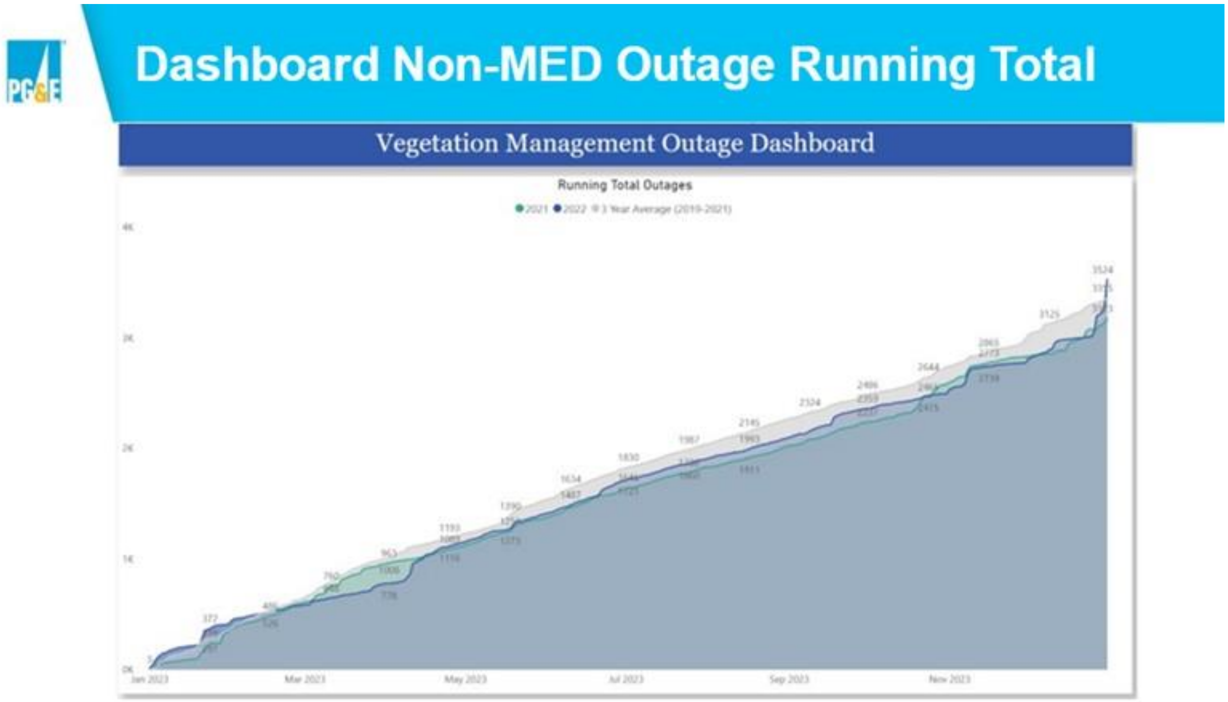
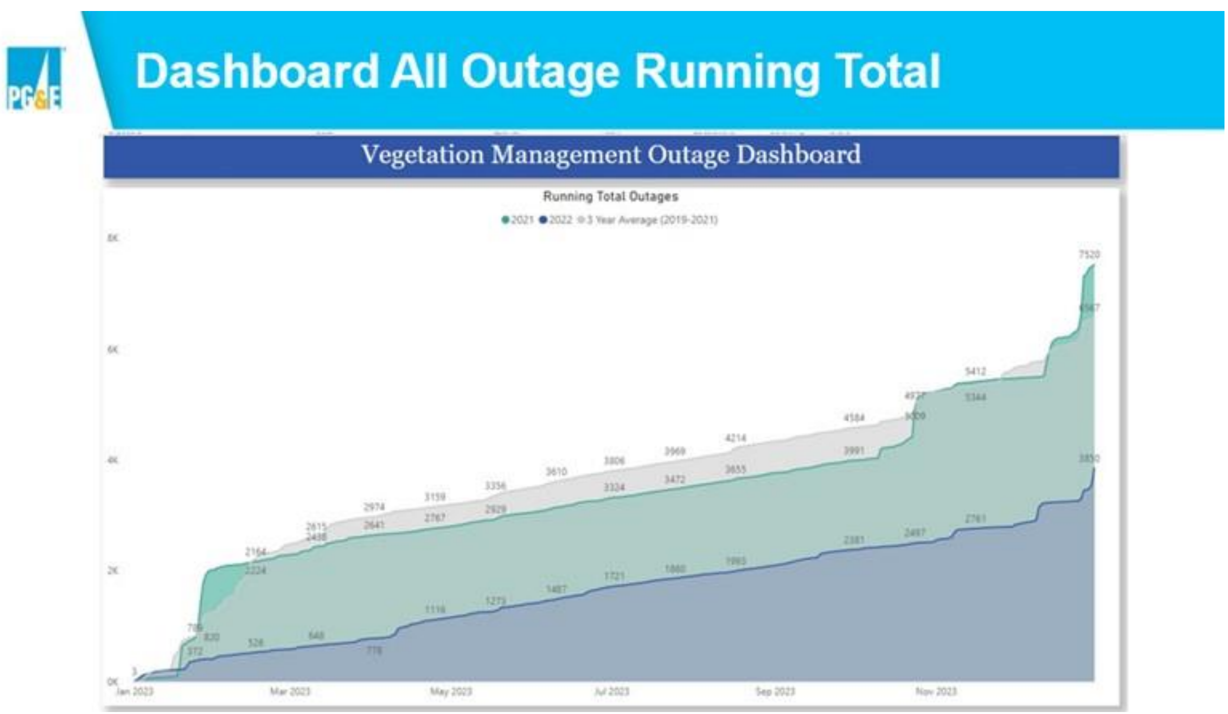
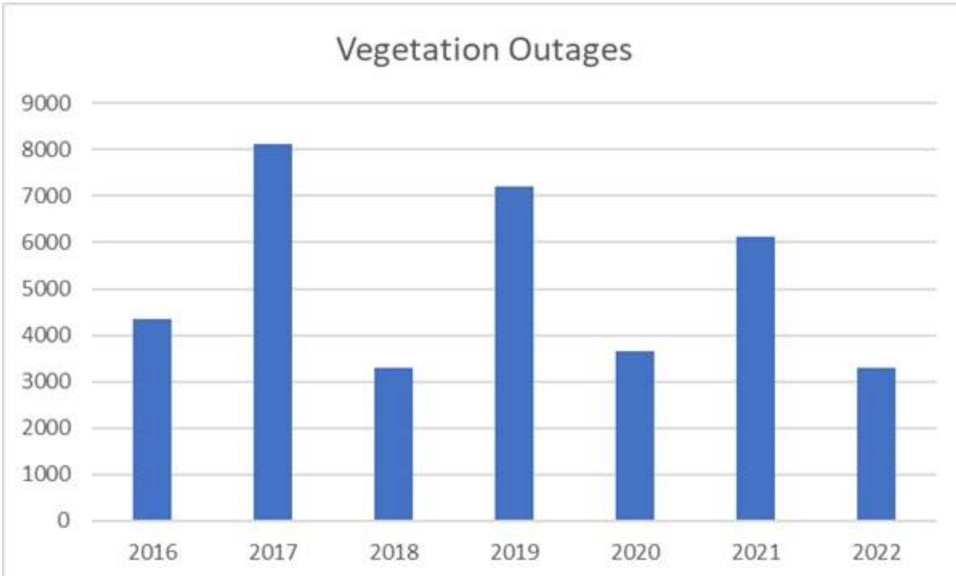


FIGURE PG&E-22-28-6:
PG&E – VEGETATION MANAGEMENT ALL OUTAGE RUNNING TOTAL DASHBOARD



Total Vegetation Outages 2016-2022

FIGURE PG&E-22-28-7:
PG&E – VEGETATION OUTAGES 2016-2022



SCE

Beginning in late 2018, SCE began implementing enhanced clearance programs to achieve greater trimming distances consistent with Decision 17-12-024, which amended GO 95 to increase recommended clearance distances at time of trimming in HFTDs. SCE believes that tree-caused circuit interruptions (TCCI) continue to serve as an appropriate data point to use in assessing the impact of SCE's enhanced clearance programs on wildfire risk mitigation.

Outage data in Table PG&E-22-28-1 represents TCCI's on SCE's distribution system as confirmed through SCE field verification. The data shows a significant decline of 60 percent in the average annual number of TCCI's between the pre-enhanced clearance period of 2015 through 2019 and the post-enhanced clearance period of 2020 through 2022. In the pre-enhanced clearance period for HFTDs, SCE experienced an annual average of approximately 148 TCCI's, while in the post-enhanced clearance period, the annual average of the number of TCCI's is currently 60, a reduction of approximately 60 percent.

As of Q4 2022, there were no reported events on SCE's transmission circuits.

TABLE PG&E-22-28-1:
SCE – AVERAGE EVENTS PRE- AND POST-ENHANCED CLEARANCES

Average Events Pre and Post Enhanced Clearances	Pre-Enhanced Clearances Avg of Annual TCCIs (2015-2019)	Post-Enhanced Clearances[a] Avg of Annual TCCIs (2020-2022)	Difference
HFTD	148.4	60	-60%
Non-HFTD	289.2	168	-42%
All	437.6	228[b]	-48%

Note: SCE's TCCI data categorization in this table is grow-in, blow-in and fall-in events with six total fault type categories: Grow-In, Blow-In, Fall-In, Human Caused, No Cause/Not tree related, and Uncategorized. This data excludes Human Caused, No Cause/Not tree related, and Uncategorized recorded events. SCE has maintained data for annual outages since 2015 and for enhanced clearance since 2020.

(a) While SCE began implementing enhanced clearance in 2019, "post-enhanced" is focused on 2020 to the present, in consideration of the time required to execute and advance expanded clearance work across SCE's HFTD in its service territory.

(b) December 2022 data is subject to change pending final verification.

Though SCE has tracked TCCIs since 2015, advancements in its work management system have allowed SCE to associate specific outage events with the specific tree(s) in its inventory since 2021. Starting in 2021, SCE's legacy outage data was updated to newer data collection standards and into Fulcrum, one of SCE's data collection tools. This additional functionality helps further SCE's insight into outage events and potentially informs future mitigation strategy.

Additionally, SCE has enhanced the functionality of its outage dashboard to facilitate a more holistic view of TCCIs across the system. These views provide insight into TCCI trending, as well as factors that may affect outage frequencies, such as at-risk species, time of year, and related weather events. Figures 1 through 3 (PG&E-22-28-8, PG&E-22-28-9, and PG&E-22-28-10) show some examples of visualization available on the dashboard. The dashboard (as reflected in Figures 1 and 2 (PG&E-22-28-8and PG&E-22-28-9)) shows a year-over-year decline in TCCIs in SCE's service area since the implementation of enhanced clearances and other wildfire mitigation initiatives. Finally, the data also indicates that SCE is experiencing flatter fluctuation of events over the year compared to prior years, with similar seasonal and storm-related spikes.

FIGURE PG&E-22-28-8:
SCE – TIME SERIES PF TCCI EVENTS (2019 AND PRIOR – PRE-ENHANCED)

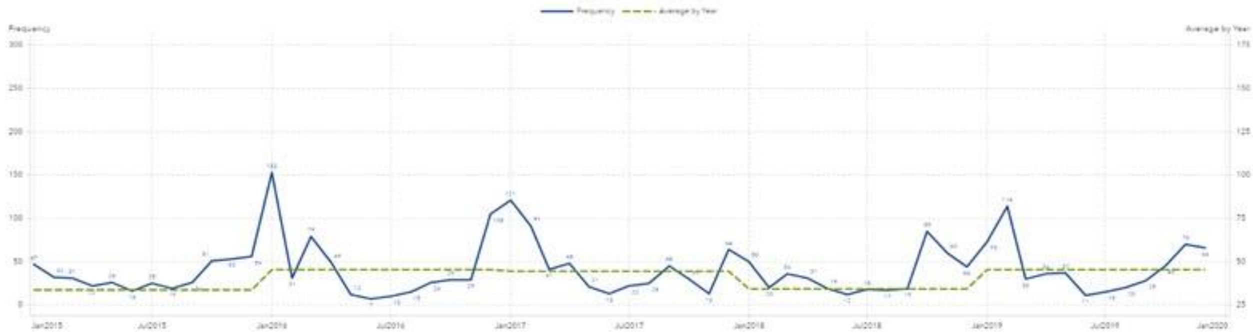


FIGURE PG&E-22-28-9:
SCE – TIME SERIES PF TCCI EVENTS (2020 AND PRIOR – PRE-ENHANCED)

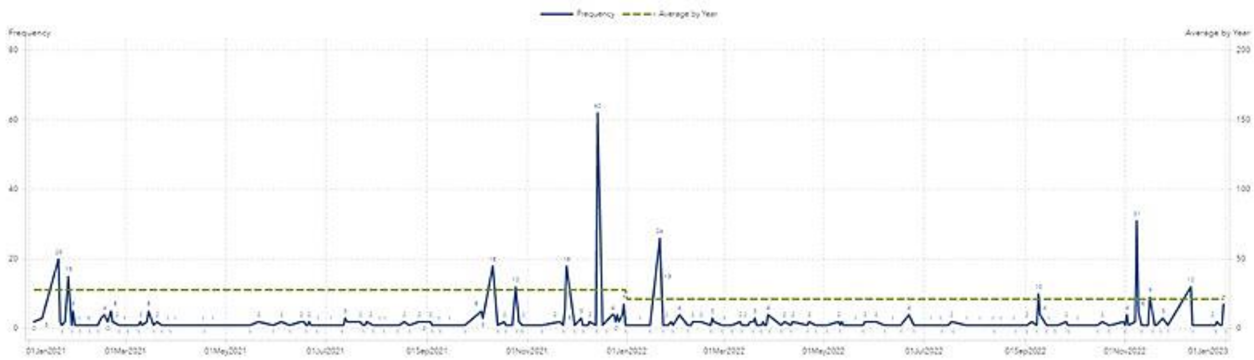
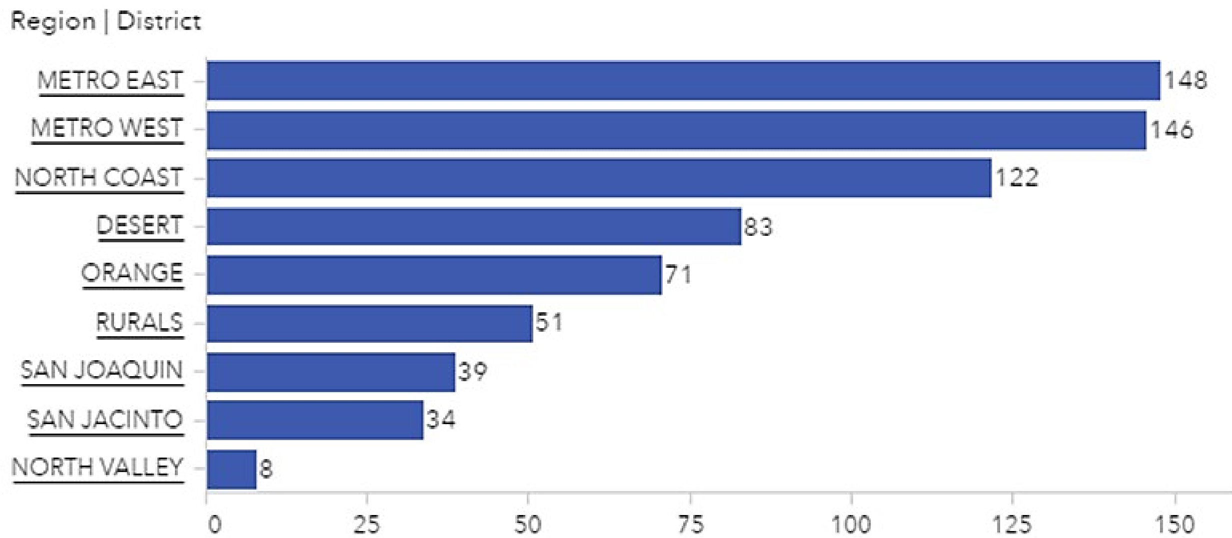


FIGURE PG&E-22-28-10:
SCE – COUNT OF GROW IN, BLOW IN, AND FALL IN TCCIS BY REGION FOR POST ENHANCED CLEARANCE (2020-2022)



During this joint effort, SCE has diligently participated in furthering the goals of this effort by helping to delineate the steps required and contributing to the selection of the 3rd party consultant for the study. Over the next few years, SCE anticipates finding more substantial evidence of the impact of enhanced clearances on the reduction of tree-related events.

ACI PG&E-22-29 – Participation in Vegetation Management Best Management Practices Scoping Meeting

Description:

VM processes and protocols for the reduction of wildfire risk are not uniform across electrical corporations.

Required Progress:

Prior to the submission of their 2023 WMPs, PG&E and all other electrical corporations (not including independent transmission operators) must participate in an Energy Safety-led scoping meeting to discuss how utilities can best learn from each other and future topics to explore regarding VM best management practices for wildfire risk reduction. This VM best management practices scoping meeting may result in additional meetings or workshops or the formation of a working group. Energy Safety will provide additional details on the specifics of this scoping meeting in due course.

PG&E Response:

The scoping meeting is scheduled for February 10, 2023, to be led by Energy Safety.

ACI PG&E-22-30 – Response Operations for Potential Fault/Outages in its Highest Risk Areas

Description:

PG&E does not discuss in its WMP its prioritized response operations for faults/outages as they occur in its highest risk areas of its service territory.

Required Progress:

In its 2023 WMP, PG&E must discuss how it has developed its processes and procedures to locate, prioritize, and respond to the locations of faults/outages in its highest risk areas as they occur. This should include discussion of how PG&E uses its wildfire consequence modeling to locate, prioritize, and respond to the locations of faults/outages in the HFTD as they happen.

PG&E Response:

PG&E uses an Operational Mitigation, EPSS (see Section 8.1.8.1 for a description of our EPSS work), to respond to faults, ignitions, and other issues detected on the grid that may result in a wildfire.

Section 8.1.8.2 describes how we locate, prioritize, and respond to faults/outages in HFRA locations.

We do not use our wildfire consequence modeling to locate, prioritize and respond to the locations of faults/outages in HFTD areas as they happen. Rather, PG&E's Emergency Operations Restoration Dispatch Supervisor, and dispatch personnel, monitor the Outage Information System/Outage Management Tool to ensure personnel are dispatched quickly to respond 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.

ACI PG&E-22-31 – PSPS Wind Threshold Change Evaluations

Description:

PG&E has not yet evaluated PSPS threshold changes as a result of installing covered conductor.

Required Progress:

In its 2023 WMP, PG&E must:

- *Coordinate with other utilities to understand the impacts of installing covered conductor and associate changes that could be made to PSPS thresholds as a result;*
- *Provide a summary of key findings, including any changes implemented to PG&E's PSPS procedures or practices;*
- *Provide any studies completed by third parties on wind speed thresholds for covered conductor, or, if not yet completed, a timeline for completion; and*
- *Provide a description and associated justification of any modifications to PSPS wind speed thresholds since the 2022 Update.*

PG&E Response:

How PG&E Coordinates with Other Utilities to Understand the Impacts of Installing Covered Conductors and the Associated Changes That Could Be Made to PSPS Thresholds as a Result

Covered conductors can potentially reduce the risk of consequences arising from the objects contacting distribution lines. In collaboration with the joint IOU team, PG&E has performed effectiveness studies to evaluate how covered conductors can reduce ignition risk compared to bare conductors. The results have been reviewed and further improvements are in progress to achieve more accurate and granular metrics regarding the effectiveness of this program.

Covered conductors reduce the probability of outage and ignitions but do not eliminate the risk entirely. The effectiveness of covered conductors is not homogenous as effectiveness is a function of surrounding vegetation risk and wind speeds.

More specifically, based on the collaboration with the joint IOU team, one of the biggest hazards during PSPS events is the potential for tree fall into line. Despite the improvements in covered conductor in reducing the probability of outage and ignition, this failure mode is something covered conductor does not largely mitigate. Therefore, PG&E is not proactively adjusting PSPS thresholds as a result of the study.

We also note that due to our PSPS modeling approach, we would not manually adjust our final PSPS risk thresholds to account for covered conductor or any other program that reduces the probability of catastrophic outcomes. Our Catastrophic Fire Probability model (discussed in Section 9) is a risk-based assessment of the probability of ignition given an outage multiplied by the probability of catastrophic fires (Fire Potential Index). Thus, we would not adjust the threshold at which PSPS is executed (each area is scoped for PSPS at the same risk threshold), but *any* program or external factor that results in a beneficial outcome would reduce the probability of ignitions and therefore *decrease* the chance of achieving the PSPS threshold.

To account for year-over-year changes, we incorporate new outage data each year into our Outage Producing Winds (OPW) and Ignition Probability Weather (IPW) machine learning models. These updates account for any updated wind to outage to ignition responses in local areas of the grid. Additionally, this is discussed in this document under the IPW model.[215] We are also exploring if adding covered conductor as a feature of the IPW model in future iterations provides benefits (see Objective SA-04).

Provide a Summary of Key findings, Including Any Changes Implemented to PG&E's PSPS Procedures or Practices

No changes to PG&E's PSPS protocols have currently been made based on studies and benchmarking of covered conductors; however, as discussed above, PG&E has continued to update PSPS models to include the improved performance of covered conductor installations.

Provide Any Studies Completed by Third Parties on Wind Speed Thresholds for Covered Conductor, or, if Not Yet Completed, a Timeline for Completion

PG&E has not yet commissioned any third-party studies on wind speed thresholds for covered conductors. However, PG&E is in the progress of performing dynamic finite element analysis (FEA) simulations of system hardened circuits, including covered conductors with maximum GO 95 wind loading to determine component specific safety factors. This analysis will be used to ensure compliance with GO 95 minimum construction safety factors for all components installed as part of system hardened designs.

The five span FEA simulations will be performed for all system hardening design configurations with various approved poles, crossarms, 3-phase configurations, covered conductor types, insulators, and span angles. The dynamic wind loading will be simulated for roughly 110 components for each simulation performed and safety factors will be calculated comparing component rated strengths vs. actual loading stresses.

Below are example images of the components and configurations used within the simulations, and stress maps on the individual system hardened components based on maximum wind loading.

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[215] See, for example, Table 6-1, PG&E's Risk Models.

FIGURE PG&E-22-31-1:
COMPONENTS AND CONFIGURATIONS USED WITHIN THE SIMULATIONS

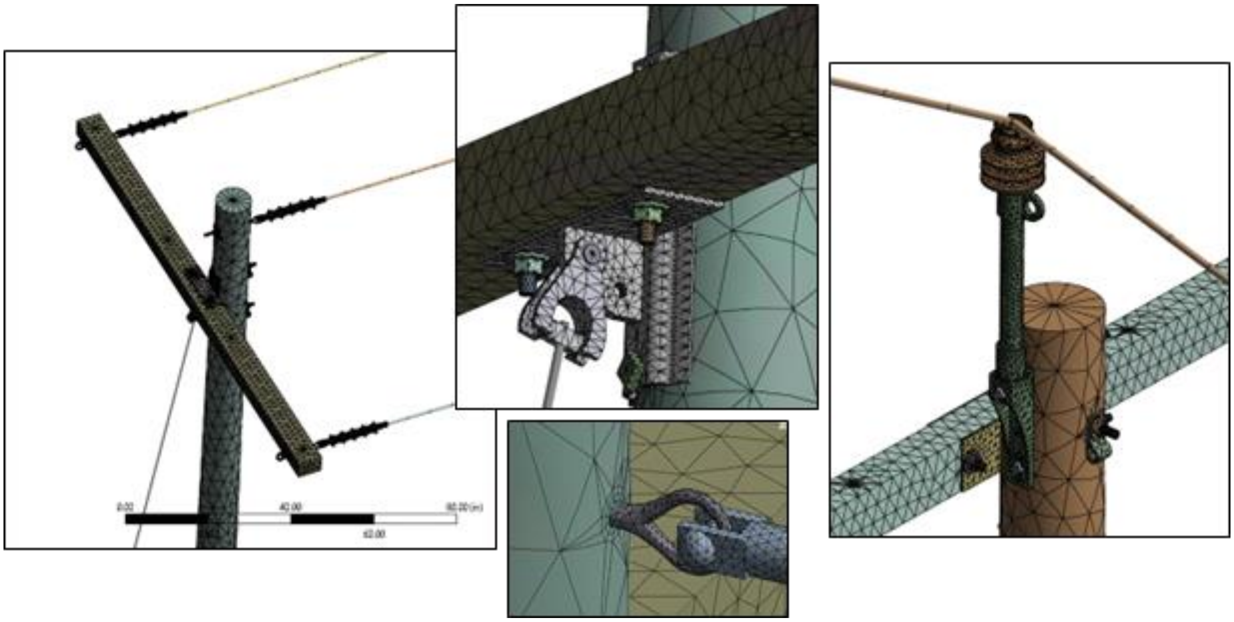


FIGURE PG&E-22-31-2:
STRESS MAPS ON THE INDIVIDUAL SYSTEM HARDENED COMPONENTS
BASED ON MAXIMUM WIND LOADING

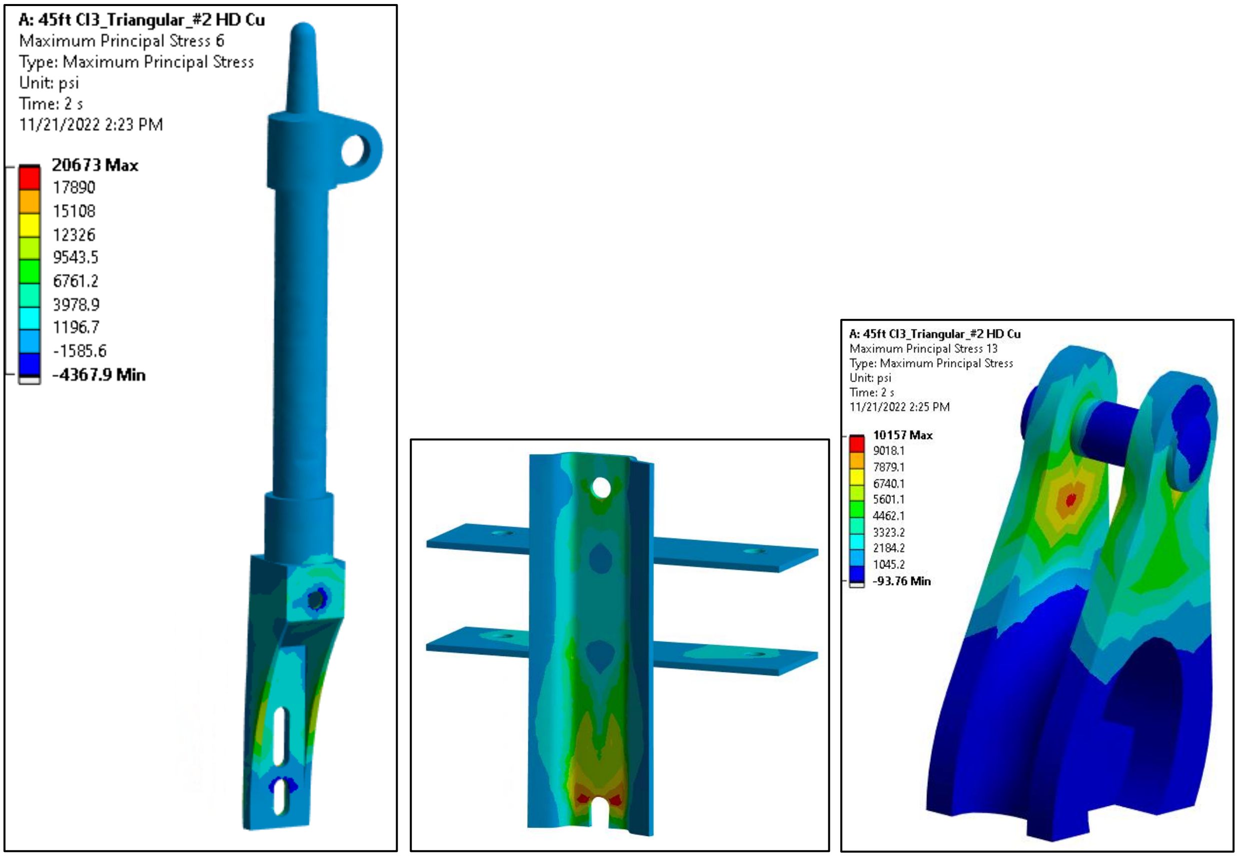
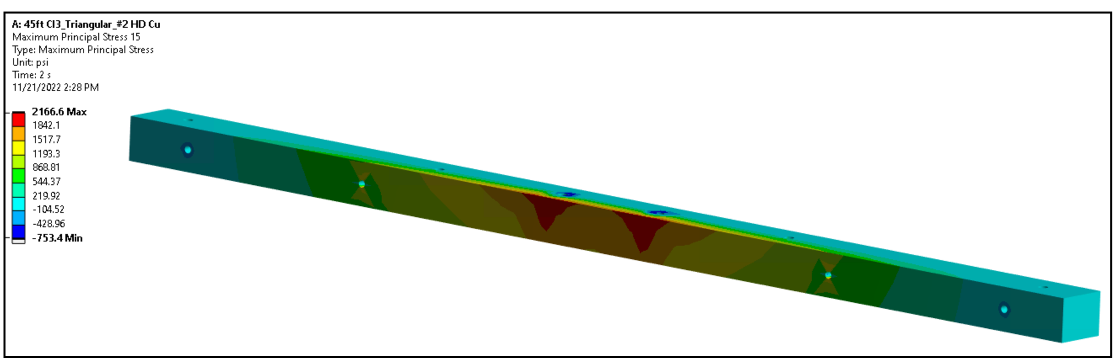


FIGURE PG&E-22-31-3:
STRESS MAP ON THE INDIVIDUAL SYSTEM HARDENED COMPONENTS
BASED ON MAXIMUM WIND LOADING



There are 32 different five-span configurations that will be evaluated. PG&E intends to finish the simulations by the end of Q2 of 2023. Results will then be shared with design engineering to determine if revisions to system hardened designs are needed. The dates by which we will make changes to overhead hardening designs will be determined based on complexity of change and predicated on completion of thorough management of change process.

Provide a Description and Associated Justification of Any Modifications to PSPS Wind Speed Thresholds Since the 2022 Update

As discussed above, PG&E does not use wind speed thresholds, and instead uses a risk-based approach for PSPS. Please see Section 8.3.5 for additional details.

ACI PG&E-22-32 – Updates on EPSS Reliability Study

Description:

PG&E has not yet included any data from 2022 in its EPSS reliability impact study.

Required Progress:

In its 2023 WMP, PG&E must provide the results from an updated 2022 EPSS reliability impact study, including any related safety impacts. This must include, but is not limited to:

- *Number of outages;*
- *Duration of outages;*
- *Number of customers impacted;*
- *Number of customers belonging to vulnerable populations (such as Access and Functional Needs, Medical Baseline, and Social Vulnerability Index) impacted;*
- *Impact on community values, including intangibles (e.g., livelihood);*
- *Response time for outages;*
- *Asset health (open work tags, asset age, etc.);*
- *Vegetation data; and*
- *Resource constraints (access issues, staffing numbers, etc.).*

PG&E must also provide an updated plan of actions being taken based on the analysis performed in its EPSS reliability impact study to reduce reliability and safety impacts of EPSS.

PG&E Response:

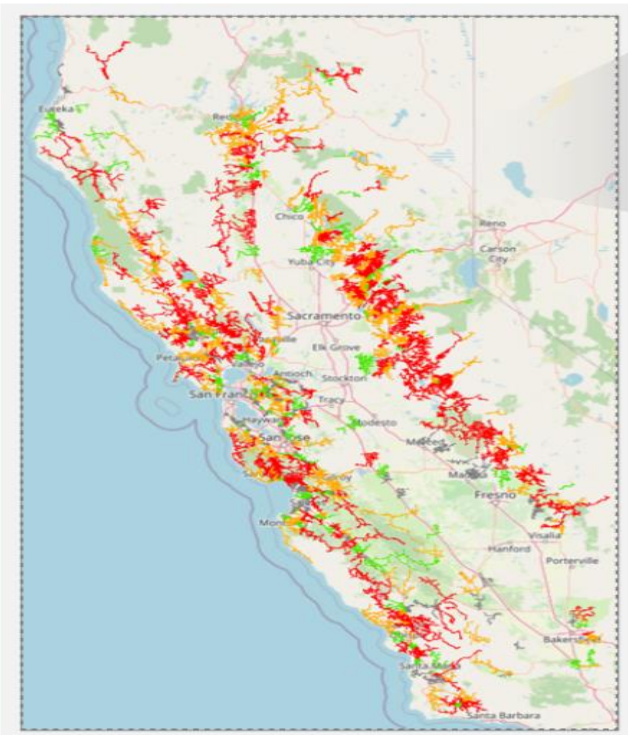
The attached 2022 Reliability Study[216] addresses eight of the first nine requirements of this this ACI (ACI PG&E-22-32). Regarding resource constraints, we do not anticipate resource constraints and we carefully plan for resources and staffing according in preparing for EPSS outages to meet our goal of responding within 60 minutes.

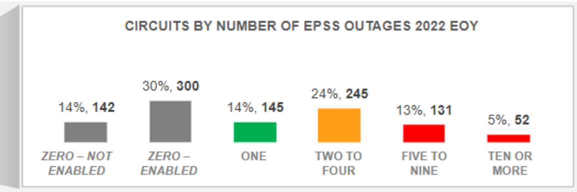
The data provided is aggregated to the CPZ that experienced outages while EPSS was enabled in 2022. What the report does not highlight is that a significant percentage of customers that were protected by EPSS in 2022 did not experience an outage. Fifty eight percent—more than 1 million customers—were not affected by EPSS in 2022. However, more than 122,000 customers experienced more than five outages while EPSS protection was enabled, 8,059 of whom experienced more than 10 outages while

216 See Attachment 2023-03-27_PGE_2023_WMP _R0_Appendix D ACI PG&E-22-32_Atch01.

EPSS was enabled. Reducing the frequency of outages for those customers will be the focus of our reliability mitigation work in 2023.

FIGURE PG&E-22-32-1:
CIRCUITS BY NUMBER OF EPSS OUTAGES 2022





IMPACT

CIRCUIT – OUTAGE COUNT	CIRCUIT COUNT	UNIQUE CUSTOMERS [1]	% TOTAL
ZERO	442	1,064,289	58%
ONE	145	284,762	16%
TWO TO FOUR	245	364,785	20%
FIVE TO NINE	131	114,164	6%
TEN OR MORE	52	8,059	<1%
TOTALS	1,015	1,836,059	100%

Based on the results of the attached 2022 EPSS Reliability Study, PG&E will be undertaking the following activities to continue to improve reliability for customers experiencing outages on circuits protected by EPSS in 2023.

1) Vegetation Management: In 2023 we will transition our Enhanced VM program to a proactive, targeted VM that is geared at improving operational performance. The program will focus on the circuit protection zones within the EPSS program with a history of vegetation caused outages. Additionally, we will continue execute our Vegetation Extent of Conditions operation from 2022 that rapidly responds to EPSS outages with vegetation as the cause and: (1) determines if there are additional vegetation risks upstream and downstream of the fault location; and (2) attempts to remove any identified vegetation.

2) Circuit Sectionalization: We have identified approximately 100 additional protective devices to install on the most reliability challenged circuit protection zones to help reduce customer count exposure should a fault occur.

3) Enablement/Disablement: In 2023 the EPSS Operations team will look to further optimize the ability to enable EPSS at a more granular level so that only those CPZs reaching the required elevated wildfire risk criteria will be enabled on a given day. This ability to enable or disable at a CPZ level will allow PG&E to reduce

enablement on sections of a circuit that geographically may exist in challenging terrain or be exposed to different weather conditions than other sections of the same circuit (e.g., a circuit segment that traverses the coastal range from west to east).

4) Multiple Outage Reviews: Optimize the existing multiple outage review process for more targeted solutions on an individual outage basis. This would include immediate Multi Outage Reviews (MOR) assignment on all CPZs that were Customers Experiencing Multiple Interruptions (CEMI) 5+ in 2023. In addition, the EPSS Operations team will work to enhance the secondary causal review outage investigation processes to endeavor to resolve more unknown cause outage activity and identify appropriate mitigations.

5) CEMI 10+ Customer Impact: The EPSS program will examine the 19 circuits and associated 57 protection zones where customers experienced more than 10 outages while EPSS was enabled. That effort will include an examination of MORs from 2023 to determine where mitigation actions reduced or eliminated outage frequency. Local engineering personnel will further examine each CPZ to identify new solutions that could be incorporated into workplans to further drive down the frequency of outages on these circuits in 2023. These solutions could include installation of additional Fault Indicators, line sensors, or additional targeted VM work, or installation of animal guards and diverters to reduce animal contact on the lines; and

6) Customer Experience: Improve customer communication tracking at the service point identification level for enhanced customer engagement related to ensuring awareness of the portfolio of direct customer support offerings. Additionally, we will examine whether there are opportunities to expand eligibility for customer support program offerings for highly impacted customers, including medical baseline customers, that may currently be affected by outages on EPSS circuits but that reside just outside the thresholds for eligibility.

ACI PG&E-22-33 – Progress on Filling Asset Inventory Data Gaps

Description:

Much of PG&E’s asset inventory is missing age, installation, or other data.

Required Progress:

In its 2023 WMP, PG&E must:

- *Outline all programs underway to improve the quality of its asset data, including timelines and progress; and*
- *Provide an update on its progress filling missing data (data holes) expressed in terms of the percent increase in data broken down by asset type and data field (installation date, asset age, manufacturer, etc.).*

PG&E Response:

Electric asset inventory data (Asset Registry) is a foundational element in enabling effective wildfire mitigation efforts. We have implemented and continue to work on targeted and systematic data quality improvements and data management programs to remediate our most critical data gaps associated with the physical assets that contribute most significantly to wildfire risk.

We acknowledge that there is missing or incomplete data in the Asset Registry database at the asset type inventory (asset record) level and at the data field (data element) level. Many of these data gaps resulted from inadequate historical data management practices, including lack of data collection standards and controls, human error, errors during conversion of paper records to digital records, and backlogs of records for processing.

In response to these historical challenges, we initiated our Asset Registry Data Quality (ARDQ) program in 2022 to develop the foundational tools, processes, and functional roles to systematically measure the quality of our most important asset data. Through this program we have developed the capability to:

- Identify and inventory our Critical Data Elements (CDE) within the Asset Registry;
- Document metadata associated with the CDEs;
- Develop and apply hundreds of data quality rules to the CDEs;
- Assign data stewardship responsibilities to staff to assess data quality of CDEs and identify targeted areas for data quality remediation;
- Provide visibility into data quality and measure progress in closing data quality gaps for CDEs through dashboards in our enterprise data and analytics platform (Palantir Foundry); and
- Publish high-quality asset data for use in Palantir Foundry-based analytics.

Through the ARDQ program, we have identified over 570 CDEs relating to 12 risk-prioritized asset types and we will continue to be expanded to other Asset Registry data and asset condition data going forward.

PG&E generally implements a risk-prioritized approach to data management and targeted data quality improvement projects related to our Asset Registry data with a near-term focus on a quantifying and addressing data gaps associated with data types that contribute most significantly to wildfire risk.[217] Our risk bowtie models for asset failures that contribute to ignition events account for approximately 86 percent of wildfire risk.

PG&E broadly targets seven data quality dimensions and specifically targets the dimension of completeness through projects aimed at filling in missing data.

Through our ARDQ program, we have quantified fill rates for critical data fields for the twelve asset components, including attributes such as installation date, manufacturer, voltage rating (where applicable), and material type (where applicable), as cited in the ACI.

Along with the ARDQ program we have implemented a series of programs and projects to improve our overall data management practices with a focus on high-risk, critical data issues within the electric Asset Registry. These programs and projects fall into three categories.

1. Asset Record Backlog Reduction: Projects and programs to address backlogs of aged As-Built and Map Correction work orders to more accurately and timely reflect assets in the field.

2. Asset Data Governance: Programs to develop, implement, improve Asset Registry related governance in the form of standards, procedures, and processes.

3. Asset Data Quality Remediation: Discrete projects aimed at addressing specific gaps at a data element and/or asset record level. These projects may also include deployment of new technologies, procedures or processes needed to remediate the root cause data quality issues. In addition to addressing data gaps within our current data model, PG&E is also undertaking efforts to expand its Asset Registry to include new data fields to enable risk analysis and asset management.

   One example of a major Asset Data Quality Remediation project is the Transmission Asset Information Collection project, which PG&E implemented to address gaps in Asset Age data for critical transmission asset components in

[217] The 12 risk-prioritized asset types are: steel; non-steel; conductor; insulator; support structures (poles); primary overhead conductor; dynamic protection device; fuse; surge arrestor; capacitor bank; voltage regulator; and service transformer. These risk-prioritized asset types are used in Table PG&E-22-33-1 in Appendix F listing current data fill rates for a subset of the data elements through 2022.

response to conditions of PG&E's probation.[218] Under this project, PG&E conducted a records search and, where available, recorded the age and date of installation of certain critical transmission tower components in HFTDs, the failure of which may result in ignition. Where asset age records were not reasonably available, PG&E is making conservative assumptions of such ages and dates of installation. Lastly, PG&E is implementing a program to determine the expected useful life of critical components factoring in field conditions and incorporating that information into its risk-based asset management programs. We have completed data collection for assets (structures) in HFTD districts in 2022 and will address the non-HFTD structures in those circuits in 2023

In Appendix F we provide tables that: list the programs underway to improve the quality of our Asset Registry data; provide an update on our progress filling in missing data; and list the projects completed in 2022.

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218 *U.S. v. PG&E*, CR 14-00175 WHA (Aug. 7, 2020) (Document 1243), Order Approving and Adopting Proposed Conditions of Probation, US District Court Northern District of California, p. 4, #7 Asset Age Condition, *stating*; "For certain critical transmission tower components in High Fire-Threat Districts, the failure of which may result in an ignition, PG&E shall conduct a reasonable search and, where available, record the age and date of installation of those components. For all other such critical transmission components and where asset age records are not reasonably available, PG&E shall make conservative assumptions of such ages and dates of installation. PG&E shall also implement a program to determine the expected useful life of critical components factoring in field conditions and incorporate that information into its risk-based asset management programs. PG&E shall begin this effort (or supplement any existing or planned initiatives) immediately and provide monthly progress reports to the Monitor team."

ACI PG&E-22-34 – Revise Process of Prioritizing Wildfire Mitigations

Description:

PG&E's current process of prioritizing wildfire mitigations assigns a high priority to undergrounding and does not demonstrate adequate weight to risk model outputs or RSE estimates.

Required Progress:

In its 2023 WMP, PG&E must conduct a quantitative analysis of alternative mitigation techniques. This must:

- *Support an overall mitigation strategy that prioritizes mitigation techniques and projects according to highest wildfire risk, addresses wildfire risk by location, and effectively uses resources;*
- *Evaluate all alternatives to undergrounding, both as individual mitigations as well as combinations, focusing on addressing location-specific risks;*
- *Incorporate RSE estimates and risk model outputs at a project level early in the decision-making process, adjusting both the scope and pace of PG&E's undergrounding program as necessary based on the analyses performed. Describe and justify the threshold at which projects move forward even as risk prioritization evolves; and*
- *Discuss how undergrounding projects are prioritized based on wildfire risk and feasibility. The discussion must include how PG&E weighs wildfire risk and project feasibility.*

PG&E Response:

PG&E quantitatively assesses the viability of alternative mitigations as part of our overall mitigation strategy that is meant to address the highest wildfire risk locations based on wildfire risk models and subject matter expertise.

In the 2022 WMP, PG&E discussed the decision tree used to inform mitigation selection at high wildfire risk location.[219] This required the review of high-risk locations informed by the WDRM for line removals and remote grids first, before considering the viability of undergrounding and overhead hardening. While we still review system hardening projects for possible line removal first, we explained in our 2022 WMP how undergrounding is a more effective mitigation in terms of long-term risk reduction[220] than overhead hardening when line removal is not possible. Therefore, we have shifted to using undergrounding as the preferred method of system hardening. This shift in strategy is contingent on the ramp-up of underground (UG) miles to drive lower unit costs, resource optimization, and longer-term contracts.

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[219] PG&E 2022 Revised WMP (Docket #2022-WMPs), (July 26, 2022), pp. 561-563.

[220] PG&E 2022 Revised WMP (Docket #2022-WMPs), (July 26, 2022), p. 553.

Given the potential to reduce unit costs through a scaled undergrounding program, PG&E developed a process for scoping, bundling, and tranching potential UG mile locations based on wildfire risk and feasibility. To account for operational and executability factors, we needed to consider the variability in cost due to the terrain difficulty when transitioning an existing OH location to UG. For instance, on average, it takes 1.25 UG install miles to replace 1 OH mile. However, at times, this multiplier can be 2-3 times greater, especially in the highest risk locations, because of existing OH circuitry traversing steep gradient and water crossings. In these areas underground miles would need to be relocated to run along roads, winding around the terrain features.

PG&E developed a measurement described in the 2022 Revised WMP[221] as the Simplified Wildfire Risk Spend Efficiency (SWRSE) or Wildfire Feasibility Efficiency (WFE) to identify where we could most efficiently reduce risk given the terrain feasibility at a particular location due to the presence of hard rock, large water crossings and/or gradient. We calculate the SWRSE as follows:

$$SWRSE = \frac{Wildfire\ Risk}{Cost} = \frac{Wildfire\ Risk}{Standard\ Cost * Feasibility\ Score}$$

While in practice the standard cost per mile of undergrounding is expected to decline over time, we assumed it to be fixed at 1 for all circuit segments so that the selection is only driven by feasibility and risk. This defines the WFE Score:

$$WFE\ Score = \frac{Line\ Weighted\ Risk\ per\ Mile}{Feasibility\ Cost\ Multiplier}$$

Importantly, the risk values span a much larger range (several orders of magnitude) than the feasibility scores (bound between 1-3), meaning that prioritizing based on simplified wildfire risk-spend efficiency produces similar results compared with prioritizing based on risk, especially at the highest end of the risk curve. Overall, PG&E evaluated the statistical significance and influence of risk compared to feasibility as shown in Figure PG&E-22-34-1 below. Figure PG&E-22-34-1 indicates that, based on the Pearson correlative coefficient, WFE and risk are 93.7 percent correlative, while feasibility is only 10.8 percent. This confirms that our prioritization of WFE is focused more on risk and less on feasibility.

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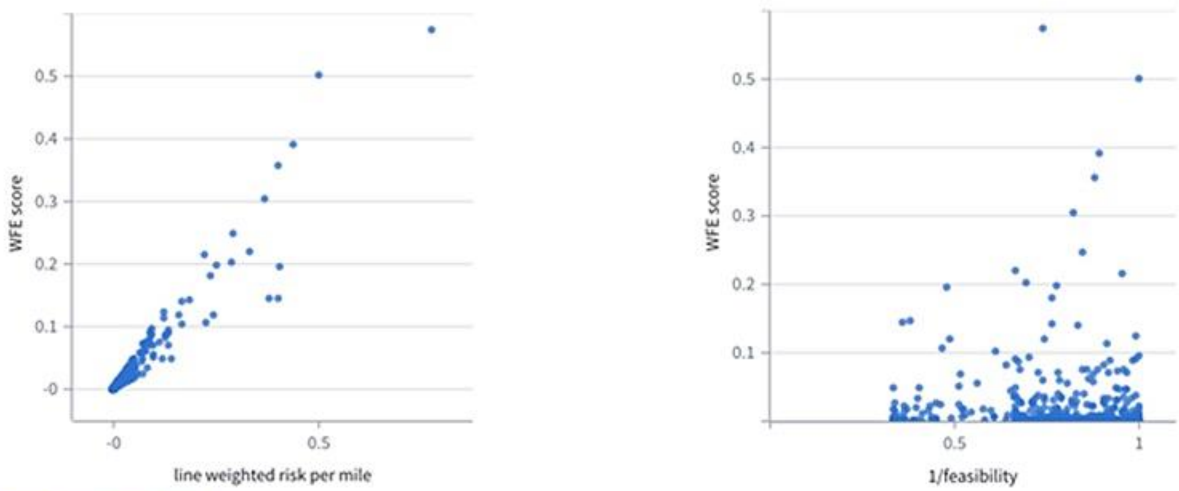
221 PG&E 2022 Revised WMP (Docket #2022-WMPs), (July 26, 2022), p. 574. For additional information see Application (A.) 21-06-021, Exhibit (PG&E-17), p. 3-5, line 22 to p. 3-9, line 8.

FIGURE PG&E-22-34-1:
CORRELATING WILDFIRE RISK AND FEASIBILITY



Pearson correlation coefficient calculated at a circuit segment level between WFE and line weighted risk per mile (.937); between 1/feasibility and line weighted risk per mile (.108); between feasibility and line weighted risk per mile (-.105). There is an indirect correlation between risk and feasibility (from steep terrain in the High Sierras contributing to increased spread and therefore consequence).

For the Undergrounding Program, we selected the roughly 8,000 OH miles with the highest SWRSE to produce roughly 10,000 miles of undergrounding. To maximize operational efficiency and minimize disruption to our customers, the selected circuit segments were then bundled together at the circuit level to allow for scoping, designs, dependency, and execution. Each bundle is comprised of circuit segments of up to 100 miles on a unique circuit and prioritizes bundling circuit segments with similar WFE scores to minimize variability within the bundle.

The Undergrounding Program portfolio was then split into three tranches of executable work generally aligning to PG&E's GRC rate case periods over the next approximately 10 years. The original designation of Tranche 1 consisted of approximately 3,000 miles of circuits resulting in the most risk reduction that would be executed in the roughly 2024 to 2026 timeframe. The remaining two tranches, which amount to approximately 7,000 UG miles, will be addressed in later years.

In December 2022, we updated our 2023-2026 undergrounding mileage[222] from the original target of approximately 3,000 miles to 1,750 miles between 2024-2026. Because of the reduced miles, naturally, this reduced the amount of risk reduced through 2026, from an original risk reduction of 33 percent in 2024-2026 to a risk reduction of approximately 18 percent.

PG&E remains committed to prioritizing risk for future projects not already scoped and included in the existing workplan, which were identified using the WDRM v2 model and WFE framework based on the 2022 WDRM v3 model. PG&E's circuit selection strategy continues to focus on creating a portfolio that allows us to maximize wildfire risk reduction for the resources deployed across our territory.

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[222] A.21-06-021, PG&E's Reply Brief, (Dec. 9, 2022), p. 329, Table 4-2.

PG&E is currently in the process of reviewing the selection methodology used to date to identify additional higher-risk circuit segments that are not currently included in 2024-2026 work plan. Given the impending release of WDRM v4 in early 2023, we expect to re-evaluate our new project selection framework leveraging the outputs of WDRM v4. The updated project selection framework (e.g., the replacement for the 2022 WFE framework) will then be used to determine the highest risk circuit segments to be incorporated into the execution workplan.

ACI PG&E-22-35 – Quantify Mitigation Benefits of Reducing PSPS Scale, Scope, and Frequency

Description:

PG&E provided in its 2022 Update a narrative including anticipated mitigation initiative benefits reducing PSPS scale, scope, and frequency for 2022, but PG&E did not provide clear projections for these benefits for 2023 in Table 11.

Required Progress:

In its 2023 WMP, PG&E must clearly show how its investments in mitigation initiatives are projected to make an impact on reducing the scale, scope, and frequency of PSPS events. PG&E must:

- *Document its estimated reductions for 2023-2026;*
- *Identify how it used mitigation initiatives in each of the PSPS events identified in the Quarterly Data Report PG&E provides to Energy Safety (e.g., how many customers impacted by PSPS events were mitigated using installed switches); and*
- *Collect and/or model the data necessary to support quantitatively demonstrating PSPS scale, scope, and frequency reduction forecasts that take into account system sectionalization, technology enhancements, and customer support program improvements.*

PG&E Response:

While PG&E uses the longer 10-year lookback to target mitigations, we incorporated only the most recent five years of the lookback to quantify the expected impacts of our mitigations because we consider the five-year timeframe more representative of expected near term future PSPS impacts. PG&E projected our 2023-2026 portfolio of undergrounding and Motorized Switch Operator (MSO) mitigation work against the 2018-2022 lookback of PSPS events to quantify their impacts on PSPS scope, frequency, and duration.

To calculate each PSPS mitigation's benefit, PG&E computed the direct impact of each mitigation activity on PSPS scope, specifically, the reduction in number of customers and associated customer hours per PSPS event. To quantify the reduction of frequency for PSPS events, PG&E evaluated whether any previous PSPS events could have been eliminated applying the mitigations.

We concluded that none of the 2022 mitigation initiatives eliminated any event.

For more details on lookback analysis, please see Table PG&E-22-35-1 below.

TABLE PG&E-22-35-1:
PSPS EVENTS LOOKBACK ANALYSIS

Mitigation Type	Incremental Customers Mitigated[(a)]	Cumulative Customers Mitigated[(a),(b)]	Incremental Mitigated (%)	Cumulative Mitigated (%)	Incremental Customers Mitigated Per Event	Incremental Customer Hours Mitigated(a)	Incremental Customer Hours Mitigated Per Event
2023 MSO	1,090	1,090	0.07%	0.07%	57	545	29
2023 UG	13,973	13,973	0.87%	0.87%	735	542,894	28,573
2023 Year Total	15,063	15,063	0.94%	0.94%	793	543,439	28,602
2024 MSO	205	1,295	0.01%	0.08%	11	102	5
2024 UG	17,965	31,938	1.13%	2.00%	946	698,059	36,740
2024 Year Total	18,170	33,233	1.15%	2.08%	956	698,161	36,745
2025 MSO	–	1,295	0.00%	0.08%	–	–	–
2025 UG	21,957	53,896	1.40%	3.37%	1,156	852,515	44,869
2025 Year Total	21,957	55,190	1.40%	3.45%	1,156	852,515	44,869
2026 MSO	–	1,295	0.00%	0.08%	–	–	–
2026 UG	29,942	83,838	1.94%	5.24%	1,576	1,162,544	61,187
2026 Year Total	29,942	85,133	1.94%	5.32%	1,576	1,162,544	61,187

(a) "Incremental Customers Mitigated", "Cumulative Customers Mitigated", and "Incremental Customer Hours Mitigated" are calculated over the whole five-year lookback analysis. The five-year lookback analysis shows the hypothetical PSPS events created by applying 2022 PSPS guidance to the weather from 2018-2022 and is used in this WMP to calculate projected PSPS customer impacts. To find the per-year average, divide the values displayed in each of these three columns by five.

(b) PG&E's Target PS-07 for 2023-2025 reflects the anticipated improvement of reducing PSPS impact of approximately 55,000 customer events as presented in this table.

Importantly, this lookback analysis accounts for the benefits of our planned 2023-2026 mitigations. Project development and refinement is still underway for the 2023-2026 mitigation workplan. Therefore, the locations and quantities of the various mitigations assumed in this analysis are based on estimates available to date. The lookback assumes the benefits from the two projects complete their planned mitigation for each respective year, regardless of when during the year they are completed. This analysis is also subject to the limitations associated with using historical weather lookback as previously described in this section.

Table PG&E-22-35-2, below, details the target reductions from PG&E's WMP mitigations.

TABLE PG&E-22-35-2:
TARGET REDUCTIONS AS A RESULT OF PG&E'S WMP MITIGATIONS

	2023 Incremental	2024 Incremental	2025 Incremental	2026 Incremental	2023-2026 Cumulative
Average PSPS Scope per Event	0.94%	1.15%	1.40%	1.94%	5.32%
Per-Customer Duration per Event[(a)]	(0.07)%	(0.01)%	0.00%	0.00%	(0.08)%
Event Frequency	0.00%	0.00%	0.00%	0.00%	0.00%

(a) Negative percentage indicates an increase in Per Customer Duration per Event. This is because MSO device replacements remove customers with short outage duration from the PSPS event which increases the average outage duration of remaining customers in the event.

Based on the mitigations discussed above, the five-year lookback analysis shows a potential 5.3 percent (4,481 customers) reduction in average PSPS event size. This percentage was used to forecast 2023-2026 values.

PACIFIC GAS AND ELECTRIC COMPANY

2023-2025 WILDFIRE MITIGATION PLAN

APPENDIX E

REFERENCED REGULATIONS, CODES, AND STANDARDS

Appendix E – Referenced Regulations, Codes, and Standards

In this appendix, PG&E provides in tabulated format a list of referenced codes, regulations, and standards, and other referenced documents.

TABLE PG&E-E-1:
LIST OF REFERENCED CODES, REGULATIONS, STANDARDS, AND OTHER REFERENCED DOCUMENTS

Category	Name of Regulation, Code or Standard	Brief Description	Link (if available)
California Legislation:	Assembly Bill 56 (Hill, 2011)	Gas corporations: rate recovery and expenditure: intrastate pipeline safety.	Bill Search (ca.gov)
California Code of Regulations (CCR):	Title 14, § 29300	State regulation requiring regulated entities to notify the Office of a fault, outage, or other anomaly occurring within the vicinity of a fire or a wildfire threat that poses a danger to infrastructure.	California Code of Regulations
	Title 14, §§ 1250-1258	Provides specific exemptions from: electric pole and tower firebreak clearance and electric conductor clearance standards and to specify when the standards apply.	
California Public Resources Code (PRC) Sections:	§ 4291 § 4292 § 4293 § 4295.5	Forests, Forestry and Range and Forage Lands > Protection of Forest Range and Forage Lands > Mountainous, Forest-, Brush- And Grass-Covered Lands.	Codes: Codes Tree - Public Resources Code - PRC (ca.gov)
	§ 4221 – 446	Forests, Forestry and Range and Forage Lands > Protection of Forest Range and Forage Lands > Mountainous, Forest-, Brush- And Grass-Covered Lands > State Responsibility Area Fire Prevention Fees > Appeals Process	

**TABLE PG&E-E-1:
LIST OF REFERENCED CODES, REGULATIONS, STANDARDS, AND
OTHER REFERENCED DOCUMENTS
(CONTINUED)**

Category	Name of Regulation, Code or Standard	Brief Description	Link (if available)
Applications before the California Public Utilities Commission (CPUC or Commission):	Application (A.) 20-06-012	PG&E's 2020 Risk Assessment and Mitigation Phase (RAMP) Report.	CPUC Proceeding Information (ca.gov)
	A.21-06-021	PG&E's Test Year 2023 General Rate Case (GRC) Application.	
California Public Utilities (PUC) Code Sections:	§ 768.6	Requires that the Commission establish standards for disaster and emergency preparedness plans and for California electrical corporations to develop and update an emergency and disaster preparedness plan	Codes: Codes Tree - Public Utilities Code - PUC (ca.gov)
	§ 8386(c)(18)	Requires an electrical corporation to construct, maintain, and operate its electrical lines and equipment in a manner that will minimize the risk of catastrophic wildfire. Each electrical corporation shall submit a wildfire mitigation plan (WMP) to the Wildfire Safety Division for review and approval.	
	§ 956.5	Owners and operators of intrastate transmission and distribution lines shall meet with local fire departments to discuss and review emergency plans.	
CPUC Decisions	Decision (D.) 02-04-026	Interim Opinion Regarding Phase 1 Issues – rulemaking on electric and gas baseline allowances.	Decision Search Form (ca.gov)
	D.09-08-029	Decision in Phase 1 – Measures to Reduce Fire Hazards in California Before the 2009 Fall Fire Season.	
	D.14-02-015	Decision Adopting Regulations to Reduce Fire Hazards Associated with OH Electric Utility Facilities and Aerial Communications Facilities.	
	D.05-10-044	Interim Opinion Approving Various Emergency Program Changes Re: Anticipated High Natural Gas Prices In Winter 2005-2006.	

TABLE PG&E-E-1:
LIST OF REFERENCED CODES, REGULATIONS, STANDARDS, AND OTHER REFERENCED DOCUMENTS
(CONTINUED)

Category	Name of Regulation, Code or Standard	Brief Description	Link (if available)
	D.06-04-055	Decision Granting the Request of the Joint Utilities to Modify Requirements for Reporting Incidents Involving Trees or Other Vegetation in the Vicinity of Power Lines.	
	D.14-02-015	Decision Adopting Regulations to Reduce the Fire Hazards Associated with Overhead (OH) Electric Utility Facilities and Aerial Communications Facilities.	
	D.14-12-025	Decision Incorporating a Risk-Based Decision-Making Framework into the Rate Case Plan and Modifying Appendix A of D.07-07-004.	
	D.17-01-009	Decision Adopting a Work Plan for the Development of Fire Map 2.	
	D.17-12-024	Decision Adopting Regulations to Enhance Fire Safety in The High Fire-Threat District.	
	D.18-12-014	Phase Two Decision Adopting Safety Model Assessment Proceeding (S-Map) Settlement Agreement with Modifications.	
	D.19-05-042	Adopting De-Energization (Public Safety Power Shutoff (PSPS)) Guidelines (Ph. 1 Guidelines).	
	D.19-05-037	Decision on PG&E's 2019 WMP Pursuant to Senate Bill (SB) 901.	
	D.19-05-042	Decision Adopting De-Energization (PSPS) Guidelines (Phase 1 Guidelines).	

TABLE PG&E-E-1:
LIST OF REFERENCED CODES, REGULATIONS, STANDARDS, AND OTHER REFERENCED DOCUMENTS
(CONTINUED)

Category	Name of Regulation, Code or Standard	Brief Description	Link (if available)
	D.19-07-015	Decision Adopting an Emergency Disaster Relief Program for Electric, Natural Gas, Water and Sewer Utility Customers.	
	D.20-03-004	Decision on Community Awareness and Public Outreach Before, During and After a Wildfire, and Explaining Next Steps for Other Phase 2 Issues.	
	D.20-05-051	Decision Adopting Phase 2 Guidelines For De-Energization of Electric Facilities to Mitigate Wildfire Risk.	
	D.20-06-003	Phase I Decision Adopting Rules and Policy Changes to Reduce Residential Customer Disconnections for the Larger California-Jurisdictional Energy Utilities.	
	D.20-12-030	Direction Regarding Marketing and Outreach of the Disadvantaged Communities – Single-Family Solar Homes.	
	D.21-05-019	Decision Addressing Phase II Issues Relating to Emergency and Disaster Preparedness Plans.	
	D.21-06-014	Decision Addressing the Late 2019 PSPS to Mitigate the Risk of Wildfire Caused by Utility Infrastructure.	
	D.21-06-034	Decision adopting Phase 3 revised and additional guidelines and rules for PSPS.	
	D.21-11-009	In the matter of the Application of Ting Telecom California for a Certificate of Public Convenience and Necessity to Provide Full Facilities-Based and Resold Competitive Local Exchange Services Throughout the State of California.	

TABLE PG&E-E-1:
LIST OF REFERENCED CODES, REGULATIONS, STANDARDS, AND OTHER REFERENCED DOCUMENTS
(CONTINUED)

Category	Name of Regulation, Code or Standard	Brief Description	Link (if available)
	D.22-10-002	Decision Resolving Litigated Issues for Southern California Edison Company's Phase 2 GRC.	
	D.22-12-027	Phase II Decision Adopting Modifications to the Risk-Based Decision-Making Framework and Directing Environmental and Social Justice Pilots.	
	D.22-03-008	Decision Closing RAMP Proceeding.	
	D.22-10-002	Decision Addressing Phase I Tracks 3 And 4 Issues –OIR to Further Develop a Risk-Based Decision-Making Framework for Electric and Gas Utilities.	
	D.22-11-033	Decision Modifying D.02-04-026 Regarding Requirements to Remain Enrolled in Medical Baseline Program.	
	Res. E-5162	Behind-The-Meter Microgrid Tariff Pursuant to D.21-01-018.	
	Res. E-5242	Allows PG&E to offer Remote Grids as a sole standard service offering under certain conditions.	
CPUC General Orders (GO):	GO 165	Inspection cycles for electric distribution facilities	CPUC General Orders (ca.gov)
	GO 166	Standards for Operation, Reliability, and Safety During Emergencies and Disasters.	
	GO 174	Rules for Electric Utility Substations.	
	GO 95	OH Electric Line Construction.	

TABLE PG&E-E-1:
LIST OF REFERENCED CODES, REGULATIONS, STANDARDS, AND OTHER REFERENCED DOCUMENTS
(CONTINUED)

Category	Name of Regulation, Code or Standard	Brief Description	Link (if available)
CPUC Investigations and Rulemakings:	Investigation (I.) 19-06-015	OII on the Commission's Motion into the Maintenance, Operations and Practices of PG&E with Respect to its Electric Facilities. Includes Envista Forensics Root Cause Analysis of 2017-2018 Wildfires.	Root Cause Analysis of the wildfires of 2017 and the Camp fire of 2018 (I.19-06-015)
	R.08-11-005	OIR to Revise and Clarify Commission Regulations Relating to the Safety of Electric Utility and Communications Infrastructure Provider Facilities.	Rulings Search Form (ca.gov)
	R.15-06-009	OIR Regarding Policies, Procedures and Rules for Regulation of Physical Security for the Electric Supply Facilities and to Establish Standards for Disaster and Emergency Preparedness Plans.	
	R.18-12-005	Decision adopting phase 3 guidelines and rules for PSPS to mitigate wildfire risk caused by utility infrastructure. Includes Access and Functional Needs (AFN) quarterly progress reports.	
	R.19-09-009	OIR Regarding Microgrids Pursuant to SB 1339 and Resiliency Strategies.	
	R.20-07-013	OIR to Further Develop a Risk-Based Decision-Making Framework for Electric and Gas Utilities.	
CPUC Resolutions:	ESRB-4 (Agenda 13027)	Directs Investor-Owned Electric Utilities to take remedial measures to reduce the likelihood of fires started by or threatening utility facilities.	ESRB-4
	ESRB-8	Resolution extending de-energizing reasonableness, notification, mitigation, and reporting requirements.	ESRB-8

**TABLE PG&E-E-1:
LIST OF REFERENCED CODES, REGULATIONS, STANDARDS, AND
OTHER REFERENCED DOCUMENTS
(CONTINUED)**

Category	Name of Regulation, Code or Standard	Brief Description	Link (if available)
Federal Emergency Management Agency Resources:	Comprehensive Preparedness Guide (CPG) 101	Developing and Maintaining Emergency Operations Plans (September 2021, V.3).	CPG 101 Link
	AL 4014G/5378 E	To revise Electric Rule 12 to allow customers to reestablish service under a prior rate schedule as part of our Emergency Consumer Protection Plan	AL are available at: Advice Letters (pge.com)
PG&E Advice Letters (AL):	AL 4145-G/5643-E	Revision to the Emergency Consumer Protection Plan under Gas and Electric Rule 1	
	AL 4249 G/5827 E2 (PG&E ID U 39 M)	Budget AL	
	AL 5918 E	Implementation Plan for Community Microgrid Enablement Program in Compliance with D.20-06-017	
	AL 6623-E	Remote Grids as Sole Standard Service Offering	
PG&E Communications, Comments, and Documents:	2022 PG&E Community Resource Center Plan	2022 PG&E Community Resource Center Plan	Wildfire Mitigation Plan (pge.com)
	Company Emergency Response Plan (CERP) Annex Maintenance and Deadlines	CERP Annex Maintenance and Deadlines	
	2020 CERP Change Record	2020 CERP Change Record	
	EMER-3001M	CERP (1/1/2023)	
	EMER-3002M	Electric Annex	
	EMER-3008M	Emergency Communication Annex to the CERP	
	EMER-3105M	Wildfire Annex	
	EMER-3106M	PSPS Annex	
	2022 Safety Outage Decision-Making Guide	2022 Safety Outage Decision-Making Guide (Power Off for Safety)	
	PSPS Event Notifications (October 2022)	PSPS Event Notifications (October 2022)	

TABLE PG&E-E-1:
LIST OF REFERENCED CODES, REGULATIONS, STANDARDS, AND OTHER REFERENCED DOCUMENTS
(CONTINUED)

Category	Name of Regulation, Code or Standard	Brief Description	Link (if available)
	PG&E GO 166 2020-2021 Annual Compliance Report	Emergency Response Plan – GO 166 Compliance for the period July 1, 2020, through December 31, 2021.	PG&E GO 166 2020-2021 Annual Compliance Report
	PG&E PSPS Report to the CPUC	Report to the CPUC, October 22-24, 2022 (Weather Event Nov. 7, 2022)	PSPS Report to CPUC
	PG&E PSPS Policies and Procedures (Emergency Managers)	PG&E PSPS Policies and Procedures (Emergency Managers)	Public Safety Power Shutoff Policies And Procedures Emergency Managers (pge.com)
	PG&E (U 39 E) 2022 AFN Plan for PSPS Support	(1/31/2022) R.18-12-005, Filed 12/13-2018	PG&E'S Access and Functional Needs Plan for Public Safety Power Shutoff Support
	PG&E Independent Safety Monitor (ISM) Status Update Report	Outlines a scope of work that includes Filsinger Energy Partners, Inc. monitoring certain safety and risk aspects of PG&E's electric and natural gas operations and infrastructure	PG&E Independent Safety Monitor Report (ca.gov)
	PG&E Removal Plan for Permanently Abandoned Transmission Facilities	Reports on PG&E's plan to resolve the remedial actions and the resulting Administrative Consent Order regarding the 2019 Kinkade Fire.	Wildfire Mitigation Plan (pge.com)
	PG&E Multi-Year Training and Exercise Plan 2023-2025 (MYTEP)	PG&E Multi-Year Training and Exercise Plan 2023-2025 (MYTEP)	Wildfire Mitigation Plan (pge.com)
	PG&E 2020 RAMP Report	RAMP (Risk Assessment and Mitigation Phase) Report.	2020 RAMP Report
	PG&E 2022 WMP (Includes Revision Notice and Maturity Survey documents)	WMP (Wildfire Mitigation Plan)	PG&E 2022 WMP
	PG&E 2023 GRC	General Rate Case: a state-mandated process for investor-owned electric and gas companies to request funding for distribution and generation costs.	PG&E 2023 GRC

TABLE PG&E-E-1:
LIST OF REFERENCED CODES, REGULATIONS, STANDARDS, AND OTHER REFERENCED DOCUMENTS
(CONTINUED)

Category	Name of Regulation, Code or Standard	Brief Description	Link (if available)
PG&E Utility Bulletins, Job Aids, Manuals, and Best Practices:	OH: Conductors 015073	Vibration Damper Requirements for Various Types of OH Conductors	[Wildfire Mitigation Plan (pge.com)]
	OH: Transmission 068177	OH Transmission Line Design Criteria	
	TD-076253-B005	De Energized Operation of Inertia SCADA MSO	
	TD-1001M	Electric Transmission Preventive Maintenance Manual	
	TD-2305M-JA02	Job Aid: OH Inspection	
	TD-2700P-06-B001	No Load Line Segment De-Energization Process	
	TD-7102P-01-B026	Enhanced Vegetation Management (VM) Transition to Distribution Routine Patrol	
	TD-7102P-01-JA01	General Best Management Practices for All VM Activities	
	TD-7101M-11	Chainsaw Operation for VM	
	TD-7112P-01-JA01	Fire Risk Assessment: Vegetation Control Pole Clearing	
	TD-7112P-01-JA02	Pole Work Status Report Types	
	TD-8123M	Electric Distribution Preventive Maintenance Manual	
PG&E Utility Procedures:	GOV-6101P-08	Enterprise Corrective Action Program Procedure	[Wildfire Mitigation Plan (pge.com)]
	GOV-6102P-06	Cause Evaluation Procedure	
	LAND-4001P-01	Substation Fire Hardening	
	LAND-5201P-01	Power Generation Powerhouse and Switchyard Defensible Space	
	PSPS-1000P-01	PSPS for Transmission and Distribution	
	RISK-6305P-01	Electric Incident Reporting On-Call Representative Procedure	
	RISK-6306P-01	Fire Incident Data Collection Plan and Reporting Procedure	

TABLE PG&E-E-1:
LIST OF REFERENCED CODES, REGULATIONS, STANDARDS, AND OTHER REFERENCED DOCUMENTS
(CONTINUED)

Category	Name of Regulation, Code or Standard	Brief Description	Link (if available)
	TD-1001P-13	Enhanced Inspection and Maintenance Requirements for Diablo Canyon and Morro Bay Power Plants OH Transmission Facilities	
	TD-1001P-14	Infrared (IR) Inspection Procedures	
	TD-1003P-01	Management of Idle Electric Transmission Line Facilities Procedure	
	TD-1006P-02	Switch Maintenance and Inspection Program for Electric Transmission	
	TD-1470P-01	Attachment 1, Application Guide Device Profile Settings (Enhanced Powerline Safety Settings (EPSS)); Fast-Tripping Scheme mode of device)	
	TD-2022P-01	Infrared (IR) Inspections of Electric Distribution Facilities	
	TD-2202P-1	EPSS-Electric Operations (EO) Restoration Dispatch Requirements	
	TD-2302P-05	Electric Distribution Maintenance Requirements for Miscellaneous OH and Underground Equipment	
	TD-2325P-01	Intrusively Inspecting, Reinforcing, and Reusing Wood Poles	
	TD-2459P-01	Idle Facility Program	
	TD-3320P-12	Substation SAP Work Management System Process	
	TD-3328P-01	Development of the Annual Substation Supplemental Inspection Plan	
	TD-3350P-10	Substation Animal Abatement Measures	
	TD-2700P-26	EPSS and Patrol Process	
	TD-7103P-02	Transmission Orchard Patrol Procedure	

TABLE PG&E-E-1:
LIST OF REFERENCED CODES, REGULATIONS, STANDARDS, AND OTHER REFERENCED DOCUMENTS
(CONTINUED)

Category	Name of Regulation, Code or Standard	Brief Description	Link (if available)
	TD-7103P-04	Transmission Integrated Vegetation Management Procedure	
	TD-7103P-09	VM Hazard Notification Procedure	
	TD-7102P-01	Distribution Routine Patrol Procedure (DRPP)	
	TD-7102P-17	VM Priority Tag Procedure	
	TD-7102P-23	VM Second Patrol Procedure	
	TD-7103P-01	Transmission Non-Orchard Routine Patrol Procedure	
	TD-7102P-26	Wood Management	
	TD-7112P-01	Vegetation Control Procedure	
	TD-8123P-100	Transmission Patrols and Enhanced Inspection Frequency Guidelines	
	TD-8123P-101	Transmission Line Corrective Notification Maintenance Strategy	
	TD-8123P-103	Electric Transmission Line Guidance for Setting Priority Codes	
PG&E Utility Standards:	TD-1001S	Electric Transmission Line Inspection and Preventative Maintenance Program	Wildfire Mitigation Plan (pge.com)
	TD-7103S	Transmission Vegetation Management (TVM) Standard	
	ENV-10002S	Environmental Release to Construction for Environmental Evaluations	
	TD-1464S	Preventing and Mitigating Fires While Performing PG&E Work	
	TD-1470S	EPSS	
	TD-2305S	Electric Distribution Maintenance Requirements	
	TD-2321S	Guidance Document Analysis Avian Protection Plan	
	TD-2325S	Inspecting, Testing, and Maintaining Wood Poles	

TABLE PG&E-E-1:
LIST OF REFERENCED CODES, REGULATIONS, STANDARDS, AND OTHER REFERENCED DOCUMENTS
(CONTINUED)

Category	Name of Regulation, Code or Standard	Brief Description	Link (if available)
	TD-3322S	Substation Equipment Maintenance Requirements	
	TD-3322S, Attachment 7	Substation Equipment Maintenance Requirements; Circuit Breaker Maintenance Template	
	TD-3328S	Substation Supplemental Inspection Program	
	TD-7102S	Distribution Vegetation Management Standard	
	TD-7112S	Vegetation Control Program	
	TD-8124S	Detailed System Inspections Framework	
	TD-9212S	EO Asset Registry Governance	
	EMER-2001S	Company Emergency Response Plans Standard	
	EMER-7001S	Enhanced Customer and Community Support During All Hazards Standard	
Third Party/Other Cited Materials:	ANSI A300	American National Standards Institute A300 – Generally accepted industry standards for tree care practices	ansi.org
	Effectiveness of Covered Conductors: Failure Mode Identification and Literature Review	Covered Conductors Phase 1 Exponent Report (12/22/21)	Effectiveness of Covered Conductors: Failure Mode ID and Lit Review
	Effectiveness and Implementation Considerations of Covered Conductors: Testing and Analysis	Exponent: Joint-IOU Covered Conductor Testing Cumulative Report (12/22/22)	Wildfire Mitigation Plan (pge.com)
	SFAC-003-4 TVM/ Federal Energy Regulatory Commission (FERC) Order# 777	Standard Federal Agency Code: TVM to manage vegetation located on transmission rights of way (FERC).	ferc.gov
	Intl. Organization for Standardization (ISO) 55001	An asset management system standard, the main objective of which is to help organizations manage the lifecycle of assets more effectively	ISO.org
	Web Content Accessibility Guidelines (WCAG) 2.0 AA	WCAG 2.0 AA accessibility standards	w3.org

TABLE PG&E-E-1:
LIST OF REFERENCED CODES, REGULATIONS, STANDARDS, AND OTHER REFERENCED DOCUMENTS
(CONTINUED)

Category	Name of Regulation, Code or Standard	Brief Description	Link (if available)
	WCAG 2.1 AA	WCAG 2.1 AA accessibility standards	

PACIFIC GAS AND ELECTRIC COMPANY

2023-2025 WILDFIRE MITIGATION PLAN

APPENDIX F

SUPPORTING DOCUMENTATION FOR NON-RISK SECTIONS

(OVERFLOW TABLES)

Appendix F – Supporting Documentation for Non-Risk Sections (Overflow Tables)

The electrical corporation must provide all detailed documentation from Section 7 in this appendix.

<Enter the associated section before adding the support documentation, e.g., Section 8.2.3.4 Fall-in Mitigation>

This section includes information that exceeds the page limits in the WMP Guidelines or is better presented in an Appendix. The information in this appendix is organized by WMP section and table number.

Appendix F.1 – 1. Executive Summary

TABLE PG&E-1.1-1:
PG&E'S PERFORMANCE AGAINST 2020-2022 QUANTITATIVE WMP INITIATIVE TARGETS

Line No.	2022 Unique ID	2022 WMP Initiative Target Name	2020 WMP Target	2020 Actual	2021 WMP Target	2021 Actual	2022 WMP Target	2022 Actual
1	B.02	Weather Stations – Installations and Optimizations	400	378	300	308	100	111
2	B.03	High-Definition Cameras – Installation	200	216	135	153	98	100
3	B.04	Distribution Fault Anticipation – Installation	N/A	1	N/A	16	40	48
4	B.05	Early Fault Detection – Installations	N/A	–	N/A	–	2	2
5	B.06	Line Sensor – Installations	20	46	N/A	67	40	63
6	C.01	Expulsion Fuse – Removal	625	643	1,200	1,429	3,000	3,085
7	C.02	Distribution Sectionalizing Devices – Install and SCADA commission	592	604	250	269	100	124
8	C.03	Transmission Line Sectionalizing – Install and SCADA commission	23	54	29	41	15	18
9	C.04	Distribution Line Motorized Switch Operator – Replacements	N/A	2	48	50	50	57
10	C.05	SCADA Recloser Equipment – Installations	N/A	20	81	81	17	17
11	C.06	Fuse Savers (Single Phase Reclosers) – Installations	N/A	–	70	71	80	81
12	C.07	Temporary Distribution Microgrids	N/A	2	8	5	4	4
13	C.08	Rincon Transformer Fuse – Replacement	N/A	–	N/A	–	1	1
14	C.09	Emergency Back-up Generation	N/A	5	23	32	15	15
15	C.10	10K Undergrounding	N/A	–	N/A	73	175	180
16	C.11	System Hardening – Distribution	220	342	180	210	470	483
17	C.12	System Hardening – Transmission	N/A	103	92	104	33	38
18	C.13	Surge Arrestor – Removals	8,850	10,263	15,000	15,465	4,590	4,621
19	C.14	Remote Grid – Operate New Remote Grid Standalone Power System (SPS) Units	N/A	–	1	1	2	2

TABLE PG&E-1.1-1:
PG&E'S PERFORMANCE AGAINST 2020-2022 QUANTITATIVE WMP INITIATIVE TARGETS
(CONTINUED)

Line No.	2022 Unique ID	2022 WMP Initiative Target Name	2020 WMP Target	2020 Actual	2021 WMP Target	2021 Actual	2022 WMP Target	2022 Actual
20	C.15	Butte County Rebuild – Undergrounding	20.0	29.3	23.0	23.6	55.0	58.7
21	D.01	Detailed Inspections – Distribution	(a)	339,026	(a)	480,749	396,000	398,184
22	D.02	Detailed Inspection Transmission – Ground	(b)	(b)	26,810	26,826	39,000	39,005
23	D.03	Detailed Inspection Transmission – Climbing	(c)	(c)	26,810	1,385	1,800	1,835
24	D.04	Detailed Inspection Transmission – Aerial	(d)	14,376	26,810	26,826	39,000	39,004
25	D.05	Infrared Inspections – Distribution	N/A	5,450	N/A	10,093	9,000	9,560
26	D.06	Supplemental Inspections – Substation Distribution	69	69	71	71	86	86
27	D.07	Supplemental Inspections – Substation Transmission	124	124	33	33	43	43
28	D.08	Supplemental Inspections – Hydroelectric Substations and Powerhouses	38	38	38	38	52	52
29	D.10	HFTD/HFRA Open Tag Reduction – Distribution	N/A	116,116	N/A	211,561	55,000	45,951
30	D.11	HFTD/HFRA Open Tag Reduction – Transmission	N/A	52,826	N/A	74,158	18,000	21,145
31	E.01	EVM	1,800	1,878	1,800	1,983	1,800	1,924
32	E.02	Pole Clearing Program	N/A	7,253	N/A	9,869	7,000	8,356
33	E.03	LiDAR Ground Inspections – Distribution	N/A	80	N/A	–	2,000	3,359
34	E.04	LiDAR Routine Inspections – Transmission	N/A	18,220	N/A	17,758	17,683	17,867
35	E.06	Defensible Space Inspections – Distribution Substation	N/A	163	N/A	172	132	132
36	E.07	Defensible Space Inspections – Transmission Substation	N/A	45	N/A	79	55	55
37	E.08	Defensible Space Inspections – Hydroelectric Substations and Powerhouses	N/A	–	N/A	63	61	61
38	E.09	Utility Defensible Space – Distribution	N/A	–	N/A	5,551	7,000	7,168

TABLE PG&E-1.1-1:
PG&E'S PERFORMANCE AGAINST 2020-2022 QUANTITATIVE WMP INITIATIVE TARGETS
(CONTINUED)

Line No.	2022 Unique ID	2022 WMP Initiative Target Name	2020 WMP Target	2020 Actual	2021 WMP Target	2021 Actual	2022 WMP Target	2022 Actual
39	E.10	Pole Clearing Program, per Public Resources Code 4292 in the CAL FIRE State Responsibility Area (SRA)[(e)]	N/A	96,775	N/A	88,163	80,258	80,208
40	F.02	EPSS – Install Settings on Distribution Line devices	N/A	–	N/A	170	3,580	3,580
41	F.04	EPSS – Reliability Improvements	N/A	–	N/A	–	50	50
42	J.01	Community Engagement – Meetings	N/A	18	N/A	13	22	23

(a) 2020 WMP Target: 100 percent of HFTD Tier 3, and 33 percent of HFTD Tier 2 assets.
2021 WMP Target: Tier 3 and Zone 1 – annually; and Tier 2 and HFRAs within the non-HFTDs – every three years (477,309).
(b) 2020 WMP Target: Transmission – aerial and visual for ~22,000 structures.
2020 Actual: 100 percent of Tier 3 (11,313) and 33 percent of Tier 2 (14,970) 25,752.
(c) 2020 WMP Target: Transmission – aerial and visual for ~22,000 structures.
2020 Actual: 100 percent of Tier 3 (338) and 33 percent of Tier 2 (779) 1,117.
(d) 2020 WMP Target: Transmission – aerial and visual for ~22,000 structures.
(e) PG&E met this target in 2022. Please see the 2022 Q4 QDR for additional details.

Appendix F.2 – 5. Overview of Service Territory

Appendix F.2.1 – 5.3.1 Fire Ecology

TABLE PG&E-5.3.1-1:
LIST OF DOCUMENTS REFERNCED IN THE FIRE ECOLOGY DISCUSSION

Anderson, M. K. 2006. The Use of Fire by Native Americans in California. pp. 17-430 in N. G. Sugihara, J. W. van Wagtendonk, K. E. Shaffer, J. O. Fites-Kaufman, and A. E. Thode, editors. Fire in California's ecosystems. University of California Press, Berkeley, California, USA.
Beaty, R. M., and A. H. Taylor. 2009. A 14,000-year sedimentary charcoal record of fire from the northern Sierra Nevada, Lake Tahoe Basin, California, USA. The Holocene 19:347-358.
Swetnam, T. W., C. H. Baisan, A. C. Caprio, P. M. Brown, R. Touchan, R. S. Anderson, and D. J. Hallett. 2009. Multi-Millennial Fire History of the Giant Forest, Sequoia National Park, California, USA. Fire Ecology 5:120-150.
Sugihara, N. G., J. W. van Wagtendonk, K. E. Shaffer, J. O. Fites-Kaufman, and A. E. Thode, editors. Fire in California's ecosystems. University of California Press, Berkeley, California, USA.
Heinselman, M. L. 1981. Fire intensity and frequency as factors in the distribution of and structure of northern ecosystems. Pages 7-57 in H. A. Mooney, T. M. Bonnicksen, N. L. Christensen, J. E. Lotan, and W. A. Reiners, editors. Fire regimes and ecosystem properties, proceedings of the conference. General Technical Report WO-GTR-26. USDA Forest Service, Washington, D.C., USA.
Romme, W. 1980. Fire history terminology: report of the ad hoc committee. Pages 135-137 in M. A. Stokes and J. H. Dieterich editors. Proceedings of the fire history workshop. General Technical Report RM-81. USDA Forest Service, Rocky Mountain Forest and Range Experiment Station, Fort Collins, Colorado, USA.
Franklin, J., C. E. Woodcock, and R. Warbington. 2000. Multi-Attribute Vegetation Maps of Forest Service Lands in California Supporting Resource Management Decisions. Photogrammetric Engineering and Remote Sensing 66:1209-1217.
Rollins, M. G. 2009. LANDFIRE: a nationally consistent vegetation, wildland fire, and fuel assessment. International Journal of Wildland Fire 18:235-249.
Van de Water, K. M., and H. D. Safford. 2011. A Summary of Fire Frequency Estimates for California Vegetation Before Euro-American Settlement. Fire Ecology 7:26-58.
Safford, H. D., and K. M. Van de Water. 2014. Using Fire Return Interval Departure (FRID) Analysis to Map Spatial and Temporal Changes in Fire Frequency on National Forest Lands in California. Research Paper PSW-RP-266. USDA Forest Service, Pacific Southwest Research Station, Albany, California, USA.
Krawchuk, M. A., M. A. Moritz, M. A. Parisien, J. Van Dorne, and K. Hayhoe. 2009. Global Pyrogeography: the Current and Future Distribution of Wildfire. PLoS One 4:e5102.
Pausas, J. G., and J. E. Keeley. 2009. A Burning Story: The Role of Fire in the History of Life. BioScience 59:593-601
Bowman, D. M. J. S., J. Balch, P. Artaxo, W. J. Bond, M. A. Cochrane, C. M. D'Antonio, R. DeFries, F. H. Johnston, J. E. Keeley, M. A. Krawchuk, C. A. Kull, M. Mack, M. A. Moritz, S. Pyne, C. I Roos, A. C. Scott, N. S. Sodhi, and T. W. Swetnam. 2017. The human dimensions of fire regimes on Earth. Journal of Biogeography 38:2223-2236.
Wills, R. 2006. Central Valley Bioregion. Pages 295-320 in N. G. Sugihara, J. W. van Wagtendonk, K. E. Shaffer, J. O. Fites-Kaufman, and A. E. Thode, editors. Fire in California's ecosystems. University of California Press, Berkeley, California, USA.

TABLE PG&E-5.3.1-1:
LIST OF DOCUMENTS REFERNCED IN THE FIRE ECOLOGY DISCUSSION
(CONTINUED)

van Wagtendonk, J. W., and D. R. Cayan. 2008. Temporal and Spatial Distribution of Lightning Strikes in California in Relation to Large-Scale Weather Patterns. Fire Ecology 4:34-56.
van Wagtendonk, J. W., and J. Fites-Kaufman. 2006. Sierra Nevada Bioregion. Pages 264-294 in N. G. Sugihara, J. W. van Wagtendonk, K. E. Shaffer, J. O. Fites-Kaufman, and A. E. Thode, editors. Fire in California's ecosystems. University of California Press, Berkeley, California, USA.
Westerling, A. L., H. G. Hidalgo, D. R. Cayan, and T. W. Swetnam. 2006. Warming and Earlier Spring Increase Western U.S. Forest Wildfire Activity. Science 313:940-943.
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Dolanc, C. R., J. H. Thorne, and H. D. Safford. 2013. Widespread shifts in the demographic structure of subalpine forests in the Sierra Nevada, California, 1934 to 2007. Global Ecology and Biogeography 22:264-276.
Keeley, J. E., W. J. Bond, R. A. Bradstock, J. G. Pausas, and P. W. Rondel. 2012. Fire in Mediterranean Ecosystems. Cambridge University Press, Cambridge, UK.

Appendix F.3 – 8. Mitigation Initiatives

Appendix F.3.1 – 8.4 Emergency Preparedness

The electrical corporation must provide all detailed documentation from Section 8.4 in this appendix.

TABLE PG&E-8.4.2-2:
EMERGENCY OPERATIONS CENTER POSITION REQUIRED TRAINING MATRIX – OCTOBER 1, 2022

		TRAINING														
		IS 100	IS-200	IS-700	IS-800	G606	IS-368	G-775	G-191	G626	ICS 300	ICS 400	IS 702 PIO	ICS 402	IS-230d	G-611
		Initial Base					**Expanded**						**Specialized**			
OIC	Officer-In-Charge													R		
Command	EOC Commander	R	R	R	R	R	R	R	R	R	R	R			R	R
Command	Deputy EOC Commander	R	R	R	R	R	R	R	R	R	R	R			R	R
Command	EOC Coordinator	R	R	R	R	R	R									
Liaison	Liaison Officer	R	R	R	R	R	R	R	R	R	R				R	R
Liaison	Assistant Liaison Officer	R	R	R	R	R	R	R	R	R	R				R	R
Liaison	Cal OES SOC AREP	R	R	R	R	R	R		R		R				R	
Liaison	Liaison Coordinator	R	R	R	R	R	R									
Liaison	Liaison Branch Director	R	R	R	R	R	R		R		R					
Liaison	Deputy Liaison Branch Director	R	R	R	R	R	R		R		R					
Liaison	Tribal Liaison	R	R	R	R	R	R		R		R					
Liaison	Agency Rep Group Supervisor	R	R	R	R	R	R		R		R					
Liaison	County/City Group Supervisor	R	R	R	R	R	R		R		R					
Customer Strategy	Customer Strategy Officer	R	R	R	R	R	R	R	R	R	R				R	R
Customer Strategy	Assistant Customer Strategy Officer	R	R	R	R	R	R	R	R	R	R				R	R
Customer Strategy	Critical Infrastructure Lead	R	R	R	R	R	R									
Customer Strategy	Notification Hawk	R	R	R	R	R	R									
Customer Strategy	Back Up Generation Lead	R	R	R	R	R	R									
Customer Strategy	Data Analyst	R	R	R	R	R	R									
Customer Strategy	Staff	R	R	R	R	R	R									
Customer Strategy	CSO Support (Agency/Coms)	R	R	R	R	R	R									
Customer Strategy	CRC Lead	R	R	R	R	R	R									
Customer Strategy	CRC Swat Team	R	R	R	R	R	R									

TABLE PG&E-8.4.2-2:
EMERGENCY OPERATIONS CENTER POSITION REQUIRED TRAINING MATRIX – OCTOBER 1, 2022
(CONTINUED)

		TRAINING														
		IS 100	IS-200	IS-700	IS-800	G606	IS-368	G-775	G-191	G626	ICS 300	ICS 400	IS 702 PIO	ICS 402	IS-230d	G-611
		Initial Base					**Expanded**						**Specialized**			
Customer Strategy	AFN Strategy Lead	R	R	R	R	R	R									
Customer Strategy	AFN Advisor	R	R	R	R	R	R									
PIO	Public Information Officer	R	R	R	R	R	R	R	R	R	R		R		R	R
PIO	Assistant Public Information Officer	R	R	R	R	R	R	R	R	R	R		R		R	R
PIO	Writers	R	R	R	R	R	R									
PIO	P&I Liaison	R	R	R	R	R	R									
PIO	Social Media	R	R	R	R	R	R									
PIO	Digital Strategy Publisher	R	R	R	R	R	R									
PIO	DCPP & Los Padres Division PIO	R	R	R	R	R	R	R	R	R	R		R		R	R
Safety	Safety Officer	R	R	R	R	R	R	R	R	R	R				R	R
Safety	Assistant Safety Officer	R	R	R	R	R	R	R	R	R	R				R	R
Operations Section	Operations Section Chief	R	R	R	R	R	R	R	R	R	R				R	R
Operations Section	Deputy Operations Section Chief	R	R	R	R	R	R	R	R	R	R				R	R
Operations Section	Distribution Branch Director	R	R	R	R	R	R	R	R		R					
Operations Section	Distribution Deputy Branch Director	R	R	R	R	R	R	R	R		R					
Operations Section	Transmission Branch Director	R	R	R	R	R	R	R	R		R					
Operations Section	Power Gen Branch Director	R	R	R	R	R	R	R	R		R					
Operations Section	Gas Branch Director	R	R	R	R	R	R	R	R		R					
Operations Section	Information Technology (IT) Branch Director	R	R	R	R	R	R	R	R		R					
Operations Section	Air Ops Branch Director	R	R	R	R	R	R	R	R		R					
Operations Section	Temp Gen Branch Director	R	R	R	R	R	R	R	R		R					
Operations Section	Temp Gen Deputy Branch Director	R	R	R	R	R	R	R	R		R					
Operations Section	Veg Branch Director	R	R	R	R	R	R	R	R		R					
Operations Section	IT BT Advisor	R	R	R	R	R	R									
Planning Section	Planning Section Chief	R	R	R	R	R	R	R	R	R	R				R	R
Planning Section	Deputy Planning Section Chief	R	R	R	R	R	R	R	R	R	R				R	R

TABLE PG&E-8.4.2-2:
EMERGENCY OPERATIONS CENTER POSITION REQUIRED TRAINING MATRIX – OCTOBER 1, 2022
(CONTINUED)

		TRAINING														
		IS 100	IS-200	IS-700	IS-800	G606	IS-368	G-775	G-191	G626	ICS 300	ICS 400	IS 702 PIO	ICS 402	IS-230d	G-611
		Initial Base					**Expanded**						**Specialized**			
Planning Section	Public Safety Power Shutoff (PSPS) Deputy Planning Chief	R	R	R	R	R	R	R	R	R	R				R	
Planning Section	Situation Unit Leader	R	R	R	R	R	R		R		R					
Planning Section	Situation Unit Support	R	R	R	R	R	R									
Planning Section	Situation Unit Support Data Analyst	R	R	R	R	R	R									
Planning Section	Documentation Unit Leader	R	R	R	R	R	R		R	R	R					
Planning Section	Documentation Unit Support	R	R	R	R	R	R									
Planning Section	Resource Management Unit Leader	R	R	R	R	R	R	R	R		R					
Planning Section	Resource Management Unit Support	R	R	R	R	R	R									
Planning Section	Resource Unit Leader	R	R	R	R	R	R	R	R		R					
Planning Section	Contract Resource Management	R	R	R	R	R	R									
Planning Section	Resource Tracking Support	R	R	R	R	R	R									
Planning Section	Demobilization Unit Leader	R	R	R	R	R	R	R	R		R					
Planning Section	GIS Technical Specialist	R	R	R	R	R	R									
Planning Section	Meteorology Technical Specialist	R	R	R	R	R	R									
Planning Section	Geosciences Technical Specialist	R	R	R	R	R	R									
Planning Section	HAWC Unit Leader	R	R	R	R	R	R				R					
Planning Section	Distribution Asset Health Specialist	R	R	R	R	R	R									
Planning Section	Transmission Asset Health Specialist	R	R	R	R	R	R									
Planning Section	BC Tech Specialist	R	R	R	R	R	R									
Planning Section	PSPS Tech Unit Leader	R	R	R	R	R	R									
Planning Section	PSPS Tech Specialist	R	R	R	R	R	R									
Planning Section	PSPS Data Analyst	R	R	R	R	R	R									
Planning Section	PSPS Portal Unit Leader	R	R	R	R	R	R									
Planning Section	PSPS Portal Unit Support	R	R	R	R	R	R									
Planning Section	PSPS Process Unit Leader	R	R	R	R	R	R									
Planning Section	PSPS Risk Analyst	R	R	R	R	R	R									

TABLE PG&E-8.4.2-2:
EMERGENCY OPERATIONS CENTER POSITION REQUIRED TRAINING MATRIX – OCTOBER 1, 2022
(CONTINUED)

		TRAINING														
		IS 100	IS-200	IS-700	IS-800	G606	IS-368	G-775	G-191	G626	ICS 300	ICS 400	IS 702 PIO	ICS 402	IS-230d	G-611
		Initial Base					**Expanded**						**Specialized**			
Planning Section	PSPS Recorder	R	R	R	R	R	R									
Planning Section	PSPS Communication Coordinator	R	R	R	R	R	R									
Logistics Section	Logistics Section Chief	R	R	R	R	R	R	R	R	R	R				R	R
Logistics Section	Deputy Logistics Section Chief	R	R	R	R	R	R	R	R	R	R				R	R
Logistics Section	Service Branch Director	R	R	R	R	R	R	R	R		R					
Logistics Section	Support Branch Director	R	R	R	R	R	R	R	R		R					
Logistics Section	Environmental/Land Response Unit Leader	R	R	R	R	R	R				R					
Logistics Section	Environmental/Land Response Unit Support	R	R	R	R	R	R									
Logistics Section	Facilities Unit Leader	R	R	R	R	R	R				R					
Logistics Section	Ground Support Unit Leader	R	R	R	R	R	R				R					
Logistics Section	Physical Security Unit Leader	R	R	R	R	R	R				R					
Logistics Section	Lodging Unit Leader	R	R	R	R	R	R									
Logistics Section	Lodging Unit Support	R	R	R	R	R	R									
Logistics Section	Base Camp/Staging Area Support	R	R	R	R	R	R									
Logistics Section	Mutual Assistance Unit Leader	R	R	R	R	R	R									
Logistics Section	MA Coordinator	R	R	R	R	R	R									
Logistics Section	MA Support	R	R	R	R	R	R									
Logistics Section	Logistics Reporting Leader	R	R	R	R	R	R									
Logistics Section	Communications Tech Specialist	R	R	R	R	R	R									
Logistics Section	Admin/Food Unit Leader	R	R	R	R	R	R									
Logistics Section	Admin/Food Unit Support	R	R	R	R	R	R									

TABLE PG&E-8.4.2-3:
MYTEP APRIL TO JUNE 2022 WILDFIRE AND PSPS EXERCISES

	Quarter 2 – 2022		
	Apr	**May**	**Jun**
Wildfire	Wildfire Seminar 12-Apr	Los Banos Pacheco 70kV Emergency Restoration Workshop 24-May	Wildfire FE (with PSPS FSE) 6/13/2017
PSPS	Emergency Field Ops Region Overviews 4/11-12	PSPS Seminar 5/3	PSPS FSE w/comms drill 6/13/2022
		PSPS TTX 5/17	N/A
		Field Ops: Humboldt 5/2-3 N Valley 5/4-5 Sonoma 5/9-10 N Bay 5/11-12 Sac 5/16-17 Sierra 5/18-19 Diablo 5/23-24 Mission 5/25-26 De Anza 5/31-6/1	Field Ops: San Jose 6/2-3 Peninsula 6/6-7 Center Coast 6/8-9 Stockton 6/13/-14 Yosemite/Kern 6/16-17 Fresno 6/21-24 East Bay 6/27-28 Los Padres 6/29-30

TABLE PG&E-8.4.2-4:
COMPANY EMERGENCY RESPONSE PLAN (CERP) ANNEX MAINTENANCE AND DEADLINES

Annexes	Review Due	New Annex Publish Date
Hazard		
Cybersecurity (North American Electric Reliability Corporation (NERC) CIP-008 compliance), EMER-3102M	Q1	
Earthquake, EMER-3101M	Q4 (NLT 11/30)	
Extreme Weather Annex (EMER-3108M)	Q3	
Infectious Disease and Pandemic Response Annex, EMER-3103M		6/30/22
PSPS Annex, EMER-3106M	April 30	
Tsunami Annex, EMER-3104M	Q3	
Wildfire Annex, EMER-3105M	Q1	
Physical Threat Annex		TBD
Functional		
Aviation Services Annex, EMER-3010M	Q3	
Canal Entry Annex, EMER-3011M	Q4 (NLT 11/30)	
Nuclear Annex		6/30/22
Disaster Rebuild, EMER-3012M	Q1	
Electric, EMER-3002M	Q2	
Emergency Communications, EMER-3008M	Q2	
Gas, EMER-3003M	Q4 (NLT 11/30)	
Human Resources, EMER-3006M	Q4 (NLT 11/30)	
Information Technology, EMER-3007M	Q2	
Logistics, EMER-3005M	Q3	
Power Generation, EMER-3004M	Q4 (NLT 11/30)	
Workforce Management/Contact Center Operations, EMER-3009M	Q4 (NLT 11/30)	

TABLE PG&E-8.4.2-5:
2020 CERP CHANGE RECORD

Topic	2019	2020	Type	Change Detail
Remove Rev symbol	Throughout	Throughout	Removed	NA
Insert Rev Symbol	Throughout	Throughout	Added	NA
Formatting	Throughout	Throughout	Formatting	NA
Base Plan	1, 1.4	1, 1.4	Removed	Removed the words “base plan”.
Emergency Management Plans	1, 1.5	1, 1.5	Revised	For bullet 1, removed “Emergency management plans” with “The CERP”; added an “s” after flow. For bullet 2, replaced the Company Emergency Response Plan with CERP; added some caps. For bullet 3, added “there are two (2) kinds of Annexes: Functional Annexes and Hazard Annexes; remove “and are generally referred to as the ___Annex. Functional annexes are updated by the function or LOB; hazard-specific annexes are updated by Emergency Preparedness and Response (EP&R). For bullet 4, removed “base plan and annexes; added caps. Figure 1- remove “and supporting Documents in title; remove is general referred to as “the CERP”
Annexes	1, 1.5, 1.5.1	1, 1.5, 1.5.1	Updated	Added annex after gas. Added Canal Entry Emergency Response Plan, Disaster Rebuild Annex, PSPS Annex and Fire Prevention Plan. Changed the footnote to 2020 and add to Nuclear, PSPS, and Wildfire.
Plan Maintenance	1.6	1.6	Added	Cybersecurity will notify EP&R within 30 days of any changes to the NERC CIP 08 requirement. EP&R will notify individuals with an emergency role within 60 days of a plan changes (roles and responsibilities, response groups, or technologies). Cybersecurity will assist EP&R to update the emergency plan within 90 days of an emergency incident or exercise.

TABLE PG&E-8.4.2-5:
2020 CERP CHANGE RECORD
(CONTINUED)

Topic	2019	2020	Type	Change Detail
Governance and Authorities	1.7	1.7	Added	State that Pacific Gas and Electric Company (PG&E) will comply with NERC CIP 008 requirements. Refer to Section 1.6 as to how we will comply.
Organizational Structure	Table 2.1	Table 2.1	Updated	Needs to be updated. Supply Chain not under Human Resources.
Fire Potential Index	2.1.1	2.1.1	Removed	Recommended removal of section as it is covered in Section 8.11.3.
Elec Transmission and Distribution Assets	2.3.1	2.3.1	Removed	Removed reference to district and divisions and separated electric distribution from transmission.
Transmission Circuit Miles and Substations	2.3.1	2.3.1	Updated	Added: information was validated by Transmission Asset Strategy and ET-GIS on 1/21/20. Deleted "Interconnected with electric power systems throughout 14 US states, 2 Canadian provinces, and parts of Mexico. Deleted "Source: LBGIS ElecMCDistricts. Deleted footnote #8 "Transmission substation information provided by Substation Asset Management 6/28/2019. Information excludes 3rd party generation, or RAS sites. Also confirmed by SEC 10-K report (for FY ending Dec 31, 2018), page 17."
Point of contact for CAISO	2.3.1	2.3.1	Removed	Deleted content "transmission and distribution operations with".
Control Centers	2.3.1	2.3.1	Added	Added "transmission" to the sentence explaining connecting transmission and distribution substations to individual customers.
Electric Trans Overview	2.3.1	2.3.1	Updated	Provided updated language to include in 2.3.1 and map.
Power Generation	2.3.3	2.3.3	No Change	NA
LiveSafe App	New	2.5.1, 8.2	Added	Provided reference to LiveSafe intranet site for employee safety.

TABLE PG&E-8.4.2-5:
2020 CERP CHANGE RECORD
(CONTINUED)

Topic	2019	2020	Type	Change Detail
EDO EM	2.5.2	2.5.2	Removed	Removed last sentence "EDO EM also serves as a liaison with public safety agencies during emergencies."
Electric Distribution Operations EM	2.5.2	2.5.2	Removed	Removed last sentence of first paragraph about serving as the liaison with public safety agencies.
DCPP Emergency Preparedness	2.5.4	2.5.4	Added	Updated to Senior Vice President Generation and Chief Nuclear Officer.
Power Generation Emergency Preparedness	2.5.5	2.5.5	Updated	Added "The VP of Power Generation has overall responsibility to manage emergency preparedness at hydro, fossil fuel, and solar power generation facilities. The Director of Engineering reports to the VP. The Public Safety Specialists report to the Director.
General Planning Assumptions	3.1.1	3.1.1	Addition	Added "and SEMS" to bullet 2.
EOC Resources Process	3.1.3.1	9.1.3.1	Updated	Replace "AC" with "REC"
Infectious Disease	3.2	3.2	Added	Added infectious disease scenario summary among others in Section3.
SOPP Model	3.2.1	3.2.1	Updated	SOPP Model leverages over 25 years of historical data.
Tsunami Hazard	3.2.3	3.2.2		"The best source of tsunami information is from the National Oceanic and Atmospheric Administration (NOAA) tsunami alert system. See link https://www.tsunami.gov. "
Cybersecurity	3.2.3	3.2.4	Removed	Remove 2018 date and "training" language in sentence after chevron graphic.
Annual Training	3.2.3	3.2.3	Revised	PG&E updates the Cybersecurity Annex to the CERP and conducts exercises to test the plan.

**TABLE PG&E-8.4.2-5:
2020 CERP CHANGE RECORD
(CONTINUED)**

Topic	2019	2020	Type	Change Detail
Threat Landscape	3.3	3.3	Added	Added “in real-time” and the EORM Program includes a horizon-scanning process which monitors threats over a longer time horizon and modified the Corporate Risk Register and cross-cutting factors as needed.
Annex Development	3.4	3.4	Updated	Removed “including cybersecurity attack and earthquake”. Added the GDL. Removed lines of business with LOB; change Coop with ConOps
Finance	4.7	4.7	Updated	Included “and other applicable filings”, “cost estimate”, internal accounting and “forecast”. Removed “debt rating agencies” from the section.
Training Requirement	3.5.1	3.5.1	Added	Added new content about new training requirements in force.
Exercises	3.5.2	3.5.2	Added	Listed the core capabilities.
PSPS Roles	5	5	Moved	Refer to the PSPS Annex for further information about PSPS-specific roles.
Public Information Officer	5.1.6	5.1.5	Updated	Edited the 3rd bullet by replacing the “classified as public” to “related to the event”.
Law Officer	5.1.8	5.1.8	Updated	Law does not develop the document retention plan. Replaced the word “develops” with the word “reviews”.
Law Officer	5.1.8	5.1.8	Updated	Changed to “Legal Officer”.
Aviation Operations Branch	5.2.1	5.2.1	Updated	Make sure Aviation removes reference to Logistics and reference to the Logistics Resource Guide
Power Generation Branch	5.2.6.	5.2.6	Updated	Added “PG Operations Team, Energy Supply Group Supervisor, Nuclear Technical Specialist, Power Gen Recovery Team”.
Power Generation Recovery Team	5.2.6	5.2.6	Updated	Added in the event of a generation emergency, the Power Generation Recovery Team maintains and documents “…for non-nuclear generation activities”.

TABLE PG&E-8.4.2-5:
2020 CERP CHANGE RECORD
(CONTINUED)

Topic	2019	2020	Type	Change Detail
Power Generation Operations Team	5.2.6.1	5.2.6.1	Added	Added who will serve on this team and general responsibilities of this team.
Energy Supply Supervisor	5.2.6.2	5.2.6.2	Added	Added responsibilities to Energy Supply Supervisor
IT Branch	5.2.8	5.2.8	Added	Added “EOC” to Section Chief and IT Branch.
Intelligence & Investigation	5.3	5.3.1	Added	Need to show the different personnel composition of the Intelligence and Investigations Section for a cybersecurity incident vs for a PSPS Event. Remedy is to show the 2 different personnel composition for I&I Section.
Planning Section	5.4	5.4	Updated	To better reflect the actual reporting, removed the Gas Resource Management box in the org structure.
Access and Functional Needs	5.4.4.1	5.4.4.1	Added	Added description of the position which includes advising the EOC Commander, Customer Strategy Officer, Planning Section Chief, and others.
Logistics Section	5.5	5.5	Updated	Updated Logistics organization chart.
Logistics Reporting Lead	5.5.1	5.5.1	Updated	Minor update to ninth & tenth bullet
Logistics Reporting	5.5.1	5.5.1	Updated	Logistics Reporting Lead” changed “points” to “lessons learned” in “Records….” Bullet. Added “as requested” at end of “Reports…” bullet.
Service/Support Branch	5.5.2	5.5.2	Reviewed	No edits required.
Physical Security	5.5.2		Updated	Added to “5.5.2.1 Physical Security Unit” this bullet:
Physical Security Unit	5.5.2.1	5.5.2.1	Updated	Added third bullet regarding them providing security at temporary emergency sites.
Food/Admin Support	5.5.2.2	5.5.2.2	Updated	Minor update to fourth bullet.

TABLE PG&E-8.4.2-5:
2020 CERP CHANGE RECORD
(CONTINUED)

Topic	2019	2020	Type	Change Detail
Admin Support /Food	5.5.2.2	5.5.2.2	Updated	In “5.5.2.2 Admin Support/Food Unit” appended “for meal counts” to “Partners…” bullet
Environmental Response Unit	5.5.2.3	5.5.2.3	Reviewed	No change.
Facilities Unit	5.5.2.4	5.5.2.4	Updated	In “5.5.2.4 Facilities Unit” appended “when activated” to “Sets up…” bullet.
Facilities Unit	5.5.2.4	5.5.2.4	Updated	Delete reference to Alternate Company Headquarters.
Base Camp /Staging Area Support	5.5.2.5	5.5.2.5	Updated	Minor update to fifth bullet.
Hotel/Berthing Unit	5.5.2.6	5.5.2.6	Removed	In “5.5.2.6 Hotels/Berthing Unit” removed “affected personnel” from “Arranges…” (first) bullet.
Hotel/Berthing Unit	5.5.2.6	5.5.2.6	Updated	Minor update to first bullet.
Air Operations	5.5.2.7	5.5.2.7	Removed	In “5.5.2.7 Ground Support Unit” removed two bullets “Coordinates aircraft needs…” and “Coordinates air charter services…”
Ground Support Unit	5.5.2.7	5.5.2.7	Updated	Removed references to Aviation.
Supply Unit	5.5.2.8	5.5.2.8	No Change	No edits required.
Materials Buyers and Service Buyers	5.5.2.9	5.5.2.9	No Change	No edits required.
Emergency Facilities	6	6	Updated	Updated content to be more specific about what our emergency facilities are.
Operations Emergency Centers	6.1.4	6.1.4	Updated	Updated the language for Gas OECs described.
Operations Emergency Center	6.1.4	6.1.4	Updated	Updated the language to remove the pre-set Gas OECs (18). Gas does not maintain 18 Gas OECs.

TABLE PG&E-8.4.2-5:
2020 CERP CHANGE RECORD
(CONTINUED)

Topic	2019	2020	Type	Change Detail
Primary and Secondary EOCs	6.1.7	6.1.7	Added	Updated section to include VERC as one of two primary EOC sites and SRVCC as the secondary site.
SIOC Operations	6.2.6	6.2.6	Added	Added “The SIOC provides security monitoring 24x7x365.”
Security Intelligence Operations Center	6.2.6	6.2.6	Updated	Updated the description of the SIOC.
Wildfire Safety Operations	6.2.7	6.2.7	Updated	Added details about the center and Wildfire Safety and Infrastructure Team.
Wildfire Safety and Infrastructure Team	6.2.7.1	Removed	Removed	Removed 6.2.7.1 from the CERP and provided to PSPS Team for inclusion in PSPS Annex. Consolidated the description into detail under WSOC section. WSIPT information was provided to PSPS to ensure that it is fully presented in the PSPS Annex. SME provided updated description of the team.
Support and Coordination Centers	6.3	6.3	Updated	Updated Mgr. title from Mgr. to Sr. Mgr.
MTCC	6.3	6.3	Updated	In “6.3 Support and Coordination Centers” Table 6.1, MTCC row, Activate and Command Authority column, changed “Manager of Warehouse Distribution” to “Sr. Manager, Materials Distribution Operations”
Base Camps	6.4	6.4	Updated	In “6.4.1 Base Camps” added bullet “Have PG&E Safety Specialist on site to oversee all safety related issues”
Emergency Field Facilities	6.4	6.4	Updated	Minor wording update.
Base Camps	6.4.1	6.4.1	Replaced	Replaced base camp picture with more current base camp picture.
Staging Sites	6.4.2	6.4.2	Updated	Minor wording edit including updating demobilization section.

TABLE PG&E-8.4.2-5:
2020 CERP CHANGE RECORD
(CONTINUED)

Topic	2019	2020	Type	Change Detail
Micro-Sites	6.4.3	6.4.3	Updated	Added language about the use of micro sites in support of PSPS events.
Materials Laydown Area	6.4.4	6.4.4	No Change	No edits required.
Community Resource Centers	6.4.5	6.4.5	Updated	Updated items provided to customers.
Community Resource Center	6.4.5	6.4.5	Updated	Updated language about the CRCs.
California State Government	7.4	7.4	Moved text Addition	Moved, added, and removed information to overview to help clarify. Mention the CA Services Act in the overview.
United State Federal Government	7.5 United State Federal Government	7.5 United State Federal Government	Moved text Addition	Moved, added, and removed information to overview to help clarify
Emergency Plan Activation	8.1 Emergency Plan Activation	8.1 Emergency Plan Activation	Moved text Removed text Addition	Moved, added, and removed information to overview to help clarify. Removed Centers on table. Too many variables and centers info down below
Emergency Incidents Levels and Activation Criteria	8.1, B	8.1, B	Added	Removed “Information Technology PG&E Incident Levels” and replaced it with “Levels of Emergency and Activation Criteria chart”.
Emergency Center Activation during Terrorist Activity	8.2	8.2	No change	Activation criteria based on terrorist scenario is reviewed by Corporate Security.
Emergency Centers Activations	8.2	8.2	Removed	Changed title and added and removed information to help clarify.
EOC On-call Staff	8.3.1.2	8.3.1.2	Added	‘Added full list of on-call team members who are sent weekly reminders of their on-call status. Added new language about on-call and on-deck teams and changes to the EOC On-call Teams program.
Establish Command	8.3.3	8.3.3	Removed	Added and removed information to help clarify.

TABLE PG&E-8.4.2-5:
2020 CERP CHANGE RECORD
(CONTINUED)

Topic	2019	2020	Type	Change Detail
SOPP	8.11.2	8.11.2	Updated	Recommended to get update from WMP. Tech writer drafted section.
FPI	8.11.3	8.11.3	Updated	Recommended to get update from WMP. Tech writer drafted section.
OPW	8.11.4	8.11.4	Updated	Recommended to get update from WMP. Tech writer drafted section.
DASH Reports	8.12.1	8.3.1.3.1	Updated	Requested to change DASH paragraph to “The Dynamic Automated Seismic Hazard (DASH) reports provide information necessary to prioritize inspections following an earthquake. Post-earthquake DASH reports are currently produced for gas, electric, generation and corporate real estate facilities.”
Debris Flow	8.12.1.5	8.3.1.3.5	Updated	Strike out pilot tested and rain tested information.
Check-in Check-out Process	9.1.1	9.1.1 Resource Check-in Check-out Process	Added	Add new content include the range of where this is implemented and what is primarily being tracked.
Roles and Responsibilities	9.1.1.1	9.1.1.1	Removed	Changed title. Added, moved, and removed information to help clarify.
Resource Management Unit	9.1.1.2, 9.1.1.5	9.1.1.2, 9.1.1.5	Updated	Removed “demobilization unit”. Added based on the size of the incident, assessed resource availability. Also updated Table 9-2 Resource Management re activation of the Resource Management Unit during OEC, REC, GEC, ETEC, or STOEC.
Vehicle and Equipment Rentals	9.1.5	9.1.5	Updated	Added reference to REC’s and updated contact information box
Materials	9.1.6	9.1.6	Updated	Minor re-wording and removal of reference to OEC and GEC

TABLE PG&E-8.4.2-5:
2020 CERP CHANGE RECORD
(CONTINUED)

Topic	2019	2020	Type	Change Detail
Logistics Section Chief	9.3.1.7	9.3.1.7	No change	No edits required.
Demobilization Order	9.3.3	9.3.3	Added	Added “GERP” as well as the Electric Annex referenced in this subsection.
Demobilization of Base Camps	9.3.4	9.3.4	No Change	No edits required.
Demobilization of Materials	9.3.5	9.3.5	Replaced	Minor update. Replaced storm with event.
Demobilization of Equipment, Vehicles and Rentals	9.3.5.1	9.3.5.1	Updated	Minor update. Added additional equipment examples and reworded section.
DCPP Emergency Plan	10.3.3	10.3.3	Added	Added the correct reference to the DCPP emergency plan.
Coordination at the Local Level	10.3.3	10.3.3	Removed	removed DCPP material. Did not seem different that everyone’s process
Contact Centers	NA	10.4.3	Added	Create a section for this information
Communicating with the Media	10.4.4	10.4.4	Updated	Replaced Marketing and Communications.
Command Call Agenda	E.2.4 #10	E.2.4 #10	Updated	Updated reference to Marketing and Communications (from Corporate Relations) with materials laydown area and CRCs. Also, updated Supply Chain to Supply Chain/Materials
Command Call Agenda	E.2.4	E. 2.4	Updated	Replace Earthquake Impact with Geohazard Impact. Remove the earthquake items listed and change to “Incident Specific Command Call topics are listed in the Technical Specialists Geosciences Document.”
Agenda	E.2.7.3	E.2.7.3	Removed	Fueling and equipment listed twice. Corrected.

TABLE PG&E-8.4.2-5:
2020 CERP CHANGE RECORD
(CONTINUED)

Topic	2019	2020	Type	Change Detail
Media Briefing	E.3.3	E.3.3	Updated	Updated the information and mentioned media briefing that could take place at the primary EOC--VERC.
Operational Period 1	F.2.1	F.2.1	Updated	Clock time 1630 added reference to materials laydown area and community resource center
Operational Period 2 and later	F.2.2	F.2.2	Updated	Removed reference to Supply Chain. Clock times 1100 and 1600. Note reference is appropriate in the initial call where the VP of Supply Chain/Materials is reporting out. When Logs. Chief is reporting out section is Logistics.
LOB On-call Teams	J	J	Added	Added new on-call guidance to the appendix.
Glossary	J.2	J.2	Revised	Changed Material Laydown Area to Materials Laydown Area

TABLE 8-43:
WILDFIRE-SPECIFIC UPDATES TO THE EMERGENCY PREPAREDNESS PLAN

ID #	Year of Updated Plan	Revision Type	Lesson Learned	Revision Description	Reference Section in Emergency Preparedness Plan
1	2/04/2022	Modification	N/A	General grammar edits and format	Throughout
2	2/04/2022	Addition	N/A	Additional information about submitting change request and bulletins	Change Request
3	2/03/2022	Deletion	N/A	Deleted section “Fire Prevention Plan”	1.6.1
4	3/04/2022	Addition	N/A	New section	1.6
5	3/04/2022	Modification	N/A	(Was 1.7) Renamed bullet “Recloser Disabling Program” to “Enhanced Powerline Safety Settings” (EPSS)	1.8
6	3/30/2022	Modification	N/A	(Was 1.8)	1.9
7	3/30/2022	Modification	N/A	(Was 1.9)	1.10
8	3/04/2022	Modification Addition	N/A	(Was 1.10) Added Section 6, After Action Reports; Added Appendices under Section 7	1.11
9	3/15/2022	Modification	N/A	Second paragraph: Replaced “satellite data” with “topography, and fuel model type mapping”	2.1.2
10	3/15/2022	Modification	N/A	Updated Figure	Figure 2-2
11	2/28/2022	Modification	N/A	Updated first two paragraphs	2.1.4
12	2/23/2022	Modification	N/A	Renamed to “Fire Index Area” and added appropriate text	2.1.5
13	3/04/2022	Modification	N/A	Updated figure with appropriate section names	Figure 2-5
14	2/16/2022	Modification	N/A	Renamed section to “EOC and Field Personnel”	2.2
15	2/28/2022	Modification	N/A	(Was 2.2.2) Updated to identify location of EOC at Vacaville	2.2.1
16	3/08/2022	Modification	N/A	(Was 2.2.3) Updated section title to identify “Teams and Crews” and restructured section	2.2.2

TABLE 8-43:
WILDFIRE-SPECIFIC UPDATES TO THE EMERGENCY PREPAREDNESS PLAN
(CONTINUED)

ID #	Year of Updated Plan	Revision Type	Lesson Learned	Revision Description	Reference Section in Emergency Preparedness Plan
17	3/16/2022	Addition	N/A	New section	2.2.2.1
18	3/21/2022	Deletion	N/A	(Was 2.2.3.1) Deleted bullet list identifying SIPT work activities	2.2.2.2
19	2/10/2022	Addition	N/A	(Was 2.2.3.2) Added additional bullets to both lists; updated text in 3d paragraph	2.2.2.3
20	3/18/2022	Modification	N/A	(Was 2.2.3.4)	2.2.2.4
21	3/03/2022	Modification Addition	N/A	(Was 2.2.4.5) New content	2.2.2.5
22	3/17/2022	Modification Addition	N/A	(Was 2.2.4.6) Added reference to Electric Annex	2.2.2.6
23	3/22/2022	Addition	N/A	New Section	2.2.2.7
24	3/17/2022	Modification Addition	N/A	(Was 2.2.4.2) added new text	2.2.2.8
25	3/03/2022	Deletion	N/A	(Was 2.2.4.3) Deleted 4th bullet, Emergency Field sites	2.2.3
26	3/21/2022	Addition	N/A	New Section	2.2.3.1
27	3/21/2022	Modification	N/A	(Was 2.2.4.1)	2.2.3.2
28	3/17/2022	Modification	N/A	(Was 2.2.4.2)	2.2.3.3
29	3/30/2022	Modification	N/A	(Was 2.2.1)	2.2.4
30	3/18/2022	Deletion	N/A	District Storm Room – Deleted	(Was 2.2.4.4)
31	3/09/2022	Modification Addition	N/A	(Was 2.2.3.3) New text	2.2.5

TABLE 8-43:
WILDFIRE-SPECIFIC UPDATES TO THE EMERGENCY PREPAREDNESS PLAN
(CONTINUED)

ID #	Year of Updated Plan	Revision Type	Lesson Learned	Revision Description	Reference Section in Emergency Preparedness Plan
32	3/18/2022	Addition	N/A	New section and subsections	3.2
33	3/30/2022	Modification	N/A	(Was 3.2)	3.3
34	3/04/2022	Modification Addition	N/A	(Was 3.2.2) Added reference to State Gov Affairs and Local Gov Affairs Representatives	3.3.2
35	3/30/2022	Modification	N/A	(Was 3.3)	3.4
36	3/18/2022	Modification Addition	N/A	(Was 3.4) New text	3.5
37	3/30/2022	Modification	N/A	(Was 3.5)	3.6
38	2/22/2022	Modification	N/A	Updated to reference the HAWC and changing staffing levels; bullet list updated	4.1.4
39	2/22/2022	Addition	N/A	New section	4.1.5
40	2/23/2022	Modification	N/A	(Was 4.1.5) Updated	4.1.6
41	3/07/2022	Modification Addition Deletion	N/A	(Was 4.1.6) Added bullet about air quality; Deleted reference to Base Camp; Added link to Safety Officer Playbook	4.1.7
42	3/24/2022	Addition	N/A	New Section	4.2.1
43	3/25/2022	Addition	N/A	Added the fourth bullet to keep it consistent with our WMP filing	4.2.2
44	3/30/2022	Modification	N/A	(Was 4.2.1)	4.2.3
45	2/18/2022	Modification	N/A	Replaced reference to R-5 Plus with PSPS threshold; changed 25 mph to 19 mph; updated 4th paragraph	4.2.4
46	3/30/2022	Modification	N/A	Renamed “Initial Response”	4.3.1
47	3/18/2022	Modification Addition	N/A	(Was 4.4.10) Added additional information about Incident Commander awareness and experience	4.3.3

TABLE 8-43:
WILDFIRE-SPECIFIC UPDATES TO THE EMERGENCY PREPAREDNESS PLAN
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ID #	Year of Updated Plan	Revision Type	Lesson Learned	Revision Description	Reference Section in Emergency Preparedness Plan
48	2/28/2022	Addition	N/A	New section	4.3.4
49	2/24/2022	Modification	N/A	(Was 4.4.9) Replaced all text	4.3.5
50	3/30/2022	Modification	N/A	(Was 4.3.3)	4.3.6
51	3/30/2022	Modification	N/A	(Was 4.3.4)	4.3.7
52	3/30/2022	Modification	N/A	(Was 4.3.5)	4.3.8
53	3/04/2022	Modification	N/A	(Was 4.4.7) Updated text, first paragraph	4.3.9
54	2/24/2022	Addition	N/A	Added figure	Figure 4-1
55	3/25/2022	Modification	N/A	(Was 4.4.3) Changed Project Management Team to Community Rebuild Program Management Team	4.4.1
56	3/30/2022	Modification	N/A	(Was 4.4.4)	4.4.2
57	2/24/2022	Modification Deletion	N/A	(Was 4.4.5) Removed unnecessary text	4.4.3
58	3/30/2022	Modification	N/A	(Was 4.4.5.1)	4.4.4
59	3/30/2022	Modification	N/A	(Was 4.4.5.2)	4.4.5
60	2/11/2022	Modification Addition	N/A	(Was 4.4.8) Added third and fourth paragraphs	4.4.6
61	3/03/2022	Modification	N/A	Restructured section; moved text	5
62	3/03/2022	Deletion	N/A	Reduced content	5.1
63	3/03/2022	Deletion	N/A	Reduced content	5.2
64	11/09/2021	Addition	N/A	New generic section; includes previous 4.4.8	6
65	2/28/2022	Addition	N/A	Added new terms to Glossary	A.2

**TABLE 8-43:
WILDFIRE-SPECIFIC UPDATES TO THE EMERGENCY PREPAREDNESS PLAN
(CONTINUED)**

ID #	Year of Updated Plan	Revision Type	Lesson Learned	Revision Description	Reference Section in Emergency Preparedness Plan
66	7/19/2022 7/29/2022 8/05/2022	Modification	N/A	Revision: Added Customer Strategy Officer to Command Staff and removed Legal Officer Revision: “Functional Business Unit” replaces “Lines of Business” here and throughout document. Revision: Text relationship Annex to CERP, NIMS and ICS.	1.3: Annex Relation to CERP
67	7/29/2022	Modification	N/A	Revision: Clarification on Standard Roles per ICS.	2.2: EOC Staffing for PSPS Event
68	7/29/2022	Modification Deletion	N/A	Revision: “General Staff” specific meaning to use capitals in this section and throughout document. Removal: “Deputy OIC” as possible delegate.	2.3: Officer-in-Charge
69	7/29/2022	Modification	N/A	Revision: EOC IC responsible for the overall command of the incident/event.	2.4: EOC Commander
70	6/30/2022	Addition	N/A	Addition: Medical baseline customers as receiving notifications before de-energization.	2.6: Customer Strategy Officer and Supporting Roles
71	7/05/2022	Modification	N/A	Revision: Title to Community Resource Center Lead	2.6.2: Community Resource Center Lead
72	7/22/2022	Modification	N/A	Revision: Title to Agency and Communications Lead—adding Agency.	2.6.3: Agency and Communications Lead

TABLE 8-43:
WILDFIRE-SPECIFIC UPDATES TO THE EMERGENCY PREPAREDNESS PLAN
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ID #	Year of Updated Plan	Revision Type	Lesson Learned	Revision Description	Reference Section in Emergency Preparedness Plan
73	7/14/2022 7/29/2022 8/01/2022	Addition Removal	N/A	Addition: “federal” to listing of types of government. Addition: “planning meetings” to listing of meetings. Removal: Cal OES state notification form process. Addition: Supporting requests and serving as single point of contact from third-party representatives to embed in PG&E’s EOC. Removal: “Receiving and reviewing Cal OES State Notifications Forms from Planning Section and sending to Cal OES Warning Center.” Removal: “In both a Single or Unified Command Structure, representatives from assisting or cooperating agencies and organizations coordinate through the LNO.”	2.7: Liaison Officer and Supporting Roles
74	7/29/2022 7/19/2022	Modification Addition	N/A	Revision: Branch Lead to replace Branch Manager Addition: Liaison Branch Lead ask for escalations/feedback.	2.7.1: Assigned City/County Agency Representatives
75	7/22/2022	Modification	N/A	Revision: Changed title to “PG&E Sate Operations Center Agency Representatives” from formerly listed as “PG&E State Operations Center Liaison Agency Representatives.”	2.7.2: PG&E State Operations Center Agency Representatives
76	7/19/2022	Modification	N/A	Revised: Description of “Legal” Advisor role formerly listed as a Note and now has section number.	2.10: Legal Advisor

TABLE 8-43:
WILDFIRE-SPECIFIC UPDATES TO THE EMERGENCY PREPAREDNESS PLAN
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ID #	Year of Updated Plan	Revision Type	Lesson Learned	Revision Description	Reference Section in Emergency Preparedness Plan
77	7/12/2022 7/13/2022	Modification Addition	N/A	Revision: Minor revisions throughout text. Revision: Title to “Team Scheduler.” Revision: Title to “Geoscience Information System Technical Specialist.” Addition: Coordinating with Customer Strategy Officer and Liaison Officer. Addition: Bullet about “Impacted personnel.” Addition: “PG&E coworkers…receive their primary messaging...through PSPS customer messaging.”	2.11.1: Human Resources Branch
78	7/11/2022 7/29/2022	Modification Addition	N/A	Revision: Minor text revisions. Addition: Working with Finance and Administration Section on purchase orders, approved vendors, and Sarbanes Oxley regulations.	2.13: Logistics Section Chief and Supporting Roles
79	7/22/2022	Deletion	N/A	Removal: For purposes of consistency removal of former Fig 2-4, Operations Section org chart.	2.14: Operations Section Chief and Supporting Roles
80	7/20/2022	Modification	N/A	Revision: Title to “Electric Transmission Branch Director” from formerly “Electric Transmission Operations Branch Director.”	2.14.3: Electric Transmission Operations Branch Director
81	7/20/2022	Addition	N/A	Addition: Utilize Deputy Branch Director for support Addition: Descriptions of actions taken by Primary and Secondary Voltage Leads.	2.14.7: Temporary Generation Branch Director and Supporting Roles
82	7/20/2022	Modification	N/A	Revision: Minor revisions to text. Additions: Added further responsibilities.	2.14.7.1: Primary Voltage Lead

TABLE 8-43:
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83	7/20/2022	Modification	N/A	Revision: Moved content to Section 2.14.7	2.14.7.1: Secondary Voltage Lead
84	7/22/2022 7/22/2022 7/29/2022	Modification Addition	N/A	Addition: “responsible for direction of Planning Section staff and development of their respective documentation.” Addition: EOC Commander has final approval over all materials produces by Planning Section. Revision: Text on responsibilities of two Deputies per ICS.	2.15: Planning Section Chief and Supporting Roles
85	7/22/2022 7/11/2022	Modification Deletion	N/A	Removal: Note on working with Deputy Planning Section Chief Revision: In Figure 2-4 Planning Section with PSPS Specific Roles revised text in guide for “All” for grey boxes to “Activates for all incidents.” Revision: Data is exported to the EOC event folder.	2.15.2: Deputy Planning Section PSPS Chief
86	7/12/2022	Modification	N/A	Revision: Corrected role title to “PSPS Comms Coordinator” from formerly listed as “External Comms Coordinator.” Revision: Minor revisions including “sequences” replacing “plans.”	2.15.3.1: PSPS Communications Coordinator
87	7/19/2022	Addition	N/A	Addition: Responsibility “Creating Asset and Vegetation Tags Situational Summary deck for OIC Decisions B+C and D+E.”	2.15.3.2: PSPS Distribution Asset Health Specialist
88	7/12/2022	Modification Addition	N/A	Revision: Corrected role title to Portal Unit Lead from formerly “Portal Unit Lead.” Addition: Event data is refreshed twice daily.	2.15.3.3: PSPS Portal Unit Leader
89	7/12/2022	Modification Addition	N/A	Revision: Corrected role title in text to “PSPS Portal Unit Support” from former listing of “Portal User Support. Addition: “PSPS Portal Unit Lead” to last bullet.	2.15.3.4: PSPS Portal Unit Support

TABLE 8-43:
WILDFIRE-SPECIFIC UPDATES TO THE EMERGENCY PREPAREDNESS PLAN
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ID #	Year of Updated Plan	Revision Type	Lesson Learned	Revision Description	Reference Section in Emergency Preparedness Plan
90	7/08/2022 7/11/2022	Addition	N/A	Addition: "Coordinating ETOR revisions with Operations Chief before and immediately after de-energization" to responsibilities.	2.15.3.5: PSPS Process Unit Leader
91	7/11/2022 7/08/2022	Addition Removal	N/A	Addition: Confirm/Cancel/Delay meetings. Removal: "Assisting with management of PSPS overall event timeline and assisting the PSPS Process Lead." Addition: "Collecting data from Meteorology" added to responsibilities.	2.15.3.6: PSPS Recorder
92	7/11/2022	Modification	N/A	Revision: Supporting presentation to OIC meetings from formerly Presenting to EOC decision making meetings.	2.15.3.7: PSPS Risk Analyst
93	7/12/2022	Modification	N/A	Revision: Interface with HAWC Lead.	2.15.3.8: PSPS Technical Lead
94	7/22/2022	Modification	N/A	Revision: To "Incident Briefing (201) from formerly "Incident Action Plan (IAP)".	2.15.4.1: Documentation Unit
95	7/12/2022	Modification	N/A	Revision: Field observation schedules to field observation to support All-Clear decisions.	2.15.4.3.1: HAWC Lead
96	8/03/2022	Addition	N/A	Addition: Responsibilities "may" include.	2.15.4.3.3: Safety Infrastructure Protection Team
97	7/22/2022	Modification	N/A	Revision: Is an "All-Hazard Unit."	2.15.4.9: Situation Unit
98	7/22/2022 8/02/2022	Addition	N/A	Addition: "Developing situational information to support external briefings and development of a common operating picture." Addition: Example for scoping abnormalities.	2.15.4.9.1: Situation Unit Leader

TABLE 8-43:
WILDFIRE-SPECIFIC UPDATES TO THE EMERGENCY PREPAREDNESS PLAN
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ID #	Year of Updated Plan	Revision Type	Lesson Learned	Revision Description	Reference Section in Emergency Preparedness Plan
99	7/11/2022	Modification	N/A	Revision: Figure 3-1 title text updated from December 2021 to April 2022.	3.2.1: Geographic scope
100	7/07/2022	Modification	N/A	Revision: Clarification on Time Places (TP) de-scoped in Figures 3-2 and 3-3.	3.2.3: Time Places
101	8/02/2022	Modification	N/A	Revision: To "Ignition Probability Weather (IPW) Index model" from former listing of "Outage Producing Winds (OPW) model."	3.3.1: Ignition Probability Weather Index (IPW)
102	7/25/2022	Modification	N/A	Revision: Updated Activity Timeline Figures 3-10, 3-11, 3-12, 3-13 to fill gaps. Formerly on three pages to now four pages.	3.3.3: PSPS Event Activity Timeline
103	7/11/2022	Modification Addition	N/A	Revision: Named HAWC and Operations as other EOC sections. Revision: Added language on how factors OIC considers are not limited to the listing. Addition: HAWC and Operations Section added to listing of groups that OIC receives situational awareness from. Revision: Figure 3-15 - text to "Patrol, make safe, and Restore power" from former listing of "Safely Restore Power." Addition: OIC will consider "various factors including but not limited to ..." Revision: To "areas" from former listing of "Time Places (TP)."	3.3.4: Decisions made by the OIC
104	8/03/2022	Deletion	N/A	Removal: As redundant to Section 3.6.1	3.5.3: Call-out Procedures

TABLE 8-43:
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ID #	Year of Updated Plan	Revision Type	Lesson Learned	Revision Description	Reference Section in Emergency Preparedness Plan
105	7/19/2022	Modification	N/A	Revision: Liaison Officer responsibility to confirm internal presenters and schedule State Executive Briefings (SEB).	3.5.5: Readiness Posture - Sections and Focus Areas
106	7/14/2022	Modification Deletion	N/A	Revision: Minor revisions to text including on simultaneous wind events. Removal: "Extra resources above FORCE and/or SOPP are allocated based on requests and availability of crews." Revision: Minor updates to Figure 3-20 REC/OEC Resource Planning Process to include "REC".	3.7.5: Resource Planning
107	8/03/2022	Addition	N/A	Addition: When requested by Meteorology..."	3.7.6: Field Observer Resourcing
108	7/22/2022	Addition	N/A	Addition: "repair" to patrol, repair and restoration.	3.8.1: PSPS Event Overview
109	8/02/2022	Addition	N/A	Addition: In Figure 3-20 PSPS Process with OIC Decisions added "(optional)" after Confirm/Cancel/Delay Meetings.	3.9: PSPS Event Scoping
110	7/22/2022	Modification	N/A	Revision: Minor edits including Cal OES Form to notify when first de-energization begins.	3.9.2: De-energization
111	7/08/2022 7/08/2022	Modification Addition	N/A	Addition: Met forecast of weather "all clears" by "All Clear Zones" including circuits. Weather "all clears also possible by entire Time Place. Revision: Fig 3-23 Steps after Weather "All Clear" – patrol of all "event specific assets at risk" to replace "patrol of every mile of lines."	3.10.1: Re-Energization Process

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WILDFIRE-SPECIFIC UPDATES TO THE EMERGENCY PREPAREDNESS PLAN
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ID #	Year of Updated Plan	Revision Type	Lesson Learned	Revision Description	Reference Section in Emergency Preparedness Plan
112	7/08/2022	Modification	N/A	Revision: Declining pressure gradients must be below meteorology PSPS guidance.	3.11.3: Re-energization Decision Factors
113	7/18/2022 7/08/2022	Modification	N/A	Revision: Details on “all clear” granularity. Revision: Add TPs to list for which OIC can declare “all clears.”	3.10.4: Weather “All Clear” Decision Methodology
114	7/18/2022	Modification	N/A	Revision: Added that unsafe Privately Owned Line (POLs) will be isolated.	3.10.5: Patrols and Restoration
115	7/18/2022	Addition	N/A	Addition: When the patrol of an individual segment is completed “(and providing a source is available)”. Addition: prioritization of segments with alphabetical order labels for criticality “(i.e., critical infrastructure when applicable, customer impacts, etc.).”	3.10.6: Step Restoration
116	7/05/2022	Modification	N/A	Revision: CRC Plan is now in 2022 Pre-season report.	4.1.1: Community Resource Centers
117	6/30/2022	Modification	N/A	Revision: Local Independent Living Centers (ILC) participating in the Disability Disaster Access and Resource (DDAR) Program with link.	4.1.2: Support for Access and Functional Needs
118	7/15/2022	Modification Addition	N/A	Revision: “refreshed” twice daily replaces “updated.” Addition: Info on External User access.	4.3.1: PSPS Portal -
119	7/22/2022	Addition	N/A	Addition: Self-Identified Vulnerable customers.	Event Specific Information for Public Safety Partners
120	7/25/2022	Modification	N/A	Revision: Fig 4-4 to include “optional” after Confirm/Cancel/Delay Meetings and asterisk (*) text for Readiness Posture about NON-regulatory requirement.	4.4: Customer Notifications

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ID #	Year of Updated Plan	Revision Type	Lesson Learned	Revision Description	Reference Section in Emergency Preparedness Plan
121	7/21/2022 8/05/2022	Deletion	N/A	Removal: Reference to Priority Notice page. Removal: "potentially" from impacted customers for de-energization, weather "all clear," and ETOR update.	4.4.1: Initial Notification Sequence
122	7/25/2022	Modification	N/A	Revision: Fig 4-5 to include "optional" after Confirm/Cancel/Delay Meetings and asterisk (*) text for Readiness Posture about NON-regulatory requirement.	4.5: De-energization Cancellation Customer Notifications
123	7/18/2022	Modification Addition	N/A	Addition: to listing self-identified vulnerable and self-identified Electricity Dependent. Revision: To "Contact Success Reporting to EOC" from formerly "Medical Baseline Contact..." Revision: In Figures 4-6 "Doorbell Ring Process" and 4-7 "Success Reporting to EOC" text listing self-identified vulnerable and self-identified Electricity Dependent.	4.6: Doorbell Ring Process
124	6/30/2022	Addition	N/A	Addition: Tenants and business in locations that have Master Meter receive electric service from PG&E, but they "are not the account holder." Addition: Exception if master meter customer is enrolled in Medical Baseline.	4.7: Master Meter Customer Notification
125	7/15/2022	Modification	N/A	Revision: Fig 4-8, updates to be automated in Step 1, revision of Step 5 to "Just before Power is Restored," new addition Step 6.	4.8: Notifications for Transmission Customers
126	7/17/2022	Modification	N/A	Revision: To "EOC SharePoint" to replace "Foundry" to store PSPS event data.	5: PSPS Data Sources
127	8/03/2022	Addition	N/A	Addition: "When requested by Meteorology…"	5.2.1: Field Observations

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ID #	Year of Updated Plan	Revision Type	Lesson Learned	Revision Description	Reference Section in Emergency Preparedness Plan
128	7/19/2022 7/19/2022	Modification Addition	N/A	Revision: Source for Internal Sit Report PSPS Deputy replaces formerly listed Sit Unit. Addition: Bullet on tags report: "Number of prioritized P1, P2 tags and EC tags to be closed out by Operations and Vegetation, Management and removed from scope."	5.3: Materials used to inform OIC
129	7/25/2022	Modification	N/A	Revision: Information available on Dashboard. Revision: Updated screenshots for Figure 5-5 "Example of Tx PSPS Scoping Dashboard" and Figure 5-6 "Example Transmission Line Scoping – OIC Summary."	5.3.1.2: Transmission Scoping Assessment and Scoping Dashboard
130	7/19/2022	Addition	N/A	Addition: PSPS Viewer is also used to incorporate potential impact to scope	5.4: PSPS Viewer
131	7/17/2022 7/19/2022	Modification	N/A	Revision: "major features" of PSIP revised with additions	5.5: PSPS Situational Intelligence Platform (PSIP)
132	7/20/2022	Modification	N/A	Revision: Fig 5-9 to include P1/P2 Tree Tags and EC Tags and clear double direction arrow between PSPS Viewer and PSIP.	5.6: Data Sources and Flow of Information
133	7/26/2022	Addition	N/A	Addition: Specified transmission to add to distribution customers.	6.3: Customer Notification Metric

TABLE 8-43:
WILDFIRE-SPECIFIC UPDATES TO THE EMERGENCY PREPAREDNESS PLAN
(CONTINUED)

ID #	Year of Updated Plan	Revision Type	Lesson Learned	Revision Description	Reference Section in Emergency Preparedness Plan
134	7/17/2022	Modification Addition	N/A	Addition: Documents located on the Cal OES PSPS Hub. Revision: Delegation of authority for Cal OES form submission. Addition: “Deputy Planning Section Chief” to text. Revision: Call Warning Center for only the first Cal OES form submission. Addition: Fig 8-3, dashboard example. Revision: Updated example of “Cal OES PSPS Dashboard – PSPS Investor-Owned Utility Notification Forms.”	8.2.1: Cal OES PSPS State Notification Form
135	7/20/2022	Modification Addition	N/A	Addition: Responsible individuals to Notifications, Complaints and Claims, Other Relevant Information and Appendix sections Revision: Updates to “Responsible Individuals” in Table 8-1 “PG&E PSPS Report to the CPUC – Sections	8.2.2: CPUC De-energization Report
136	7/20/2022	Deletion Addition	N/A	Removal: Sentence about lessons learned in action descriptions Addition: New Table 8-2 “PG&E PSPS Report to CPUC - PSDR” with PSDR Sections and Responsible LOBs. Removal: Sentence about details being confirmed at a future date.	8.2.3: Pre-Season Report
137	7/20/2022	Modification	N/A	Revision: In Table 8-3 “PG&E PSPS Report to the CPUC – POSTR 1” under Responsible Individuals “CC PSPS Program Team” replaces “CC Regulatory Strategy.”	8.2.4: Post-Season Report

TABLE 8-43:
WILDFIRE-SPECIFIC UPDATES TO THE EMERGENCY PREPAREDNESS PLAN
(CONTINUED)

ID #	Year of Updated Plan	Revision Type	Lesson Learned	Revision Description	Reference Section in Emergency Preparedness Plan
138	7/20/2022	Modification Addition	N/A	Revision: Due date is March 1st replaces former listing of April 1. Addition: CC PSPS Program team to Decision Specified Requirements and Safety and Enforcement Division (SED) Specified Requirements sections. Removal: CC Regulatory strategy from Decision Specified Requirements and SED Specified Requirements sections.	8.2.5: Post-Season Data Report
139	7/14/2022	Addition	N/A	Addition: New Section added with link to Business Continuity Plans.	Appendix F: PSPS Business Continuity

Confidential contact information has been removed from this public version of Table 8-44. A copy of this table with contact information is available in Appendix I.

TABLE 8-44:
STATE AND LOCAL AGENCY COLLABORATION(S)

Name of State or Local Agency	Point of Contact and Information	Emergency Preparedness Plan Collaboration* – Last Version of Plan Agency Collaborated	Emergency Preparedness Plan Collaboration – Collaborative Role	Memorandum of Agreement (MOA)?	Brief Description of MOA
Alameda County	Derrick Thomas, ACFD Div Chief/Emergency Management	Regional Working Group: Bay Area (12/9/22)	Review and provide feedback	No	N/A
Alameda County	Kristi Duenas, OEE Emergency Services Coordinator	Regional Working Group: Bay Area (12/9/22)	Review and provide feedback	No	N/A
Alameda County	Lincoln Casimere, ACFD Emergency Manager	Regional Working Group: Bay Area (12/9/22)	Review and provide feedback	No	N/A
Alameda County	Paul Stokes, Captain OES	Regional Working Group: Bay Area (12/9/22)	Review and provide feedback	No	N/A
Alpine County	Tom Minder, OES Director/Sheriff	Regional Working Group: Central Valley (12/7/22)	Review and provide feedback	No	N/A
Amador County	Jason Navarre OES Coordinator	Regional Working Group: Central Valley (12/7/22)	Review and provide feedback	No	N/A
Amah Mutsun Tribal Band	Valentin Lopez, Chairman	N/A	N/A	No	N/A
American Indian Council of Mariposa County (Southern Sierra Miwuk Nation)	Sandra Vasquez, Tribal Chair	N/A	N/A	No	N/A
Berry Creek Rancheria	Jennifer Santos, Tribal Administrator	Regional Working Group: North Valley/Sierra (12/7/22)	Review and provide feedback	No	N/A

TABLE 8-44:
STATE AND LOCAL AGENCY COLLABORATION(S)
(CONTINUED)

Name of State or Local Agency	Point of Contact and Information	Emergency Preparedness Plan Collaboration* – Last Version of Plan Agency Collaborated	Emergency Preparedness Plan Collaboration – Collaborative Role	Memorandum of Agreement (MOA)?	Brief Description of MOA
Big Lagoon Rancheria	Virgil Moorehead, Chairperson	N/A	N/A	No	N/A
Big Sandy Rancheria	Elizabeth Kipp, Chairperson	Regional Working Group: Central Valley (12/7/22)	Review and provide feedback	No	N/A
Big Valley Band of Pomo	Veronica Aparicio, Executive Assistant	Regional Working Group: North Coast (12/8/22)	Review and provide feedback	No	N/A
Blue Lake Rancheria	Anita Huff, OES Director	Regional Working Group: North Coast (12/8/22)	Review and provide feedback	No	N/A
Buena Vista Rancheria	Michael DeSpain, Chief Operations Officer	N/A	N/A	No	N/A
Butte County	Joshua Jimerfield, OES Director	Regional Working Group: North Valley/Sierra (12/7/22)	Review and provide feedback	No	N/A
Butte Tribal Council	Ren Reynolds, General	N/A	N/A	No	N/A
CAL FIRE	Bob Counts, Battalion Chief	Fire Chiefs and CAL FIRE Wildfire Briefing (2/16/22)	Review and provide feedback	No	N/A
CAL FIRE	Bret Gouvea, Chief, County Fire Warden	Fire Chiefs and CAL FIRE Wildfire Briefing (2/16/22)	Review and provide feedback	No	N/A
CAL FIRE	Brian Eagan, Battalion Chief	Fire Chiefs and CAL FIRE Wildfire Briefing (2/16/22)	Review and provide feedback	No	N/A

TABLE 8-44:
STATE AND LOCAL AGENCY COLLABORATION(S)
(CONTINUED)

Name of State or Local Agency	Point of Contact and Information	Emergency Preparedness Plan Collaboration* – Last Version of Plan Agency Collaborated	Emergency Preparedness Plan Collaboration – Collaborative Role	Memorandum of Agreement (MOA)?	Brief Description of MOA
CAL FIRE	Brian Estes, Chief, N/A	Fire Chiefs and CAL FIRE Wildfire Briefing (2/16/22)	Review and provide feedback	No	N/A
CAL FIRE	Brian Estes, Local Cal Fire	Fire Chiefs and CAL FIRE Wildfire Briefing (2/16/22)	Review and provide feedback	No	N/A
CAL FIRE	Brian Mackwood, Assistant Chief	Fire Chiefs and CAL FIRE Wildfire Briefing (2/16/22)	Review and provide feedback	No	N/A
CAL FIRE	CAL FIRE Butte County, Fire Chief	Fire Chiefs and CAL FIRE Wildfire Briefing (2/16/22)	Review and provide feedback	No	N/A
CAL FIRE	CAL FIRE Butte County, General CAL FIRE	Fire Chiefs and CAL FIRE Wildfire Briefing (2/16/22)	Review and provide feedback	No	N/A
CAL FIRE	CAL FIRE Placer County, Emergency Command Center	Fire Chiefs and CAL FIRE Wildfire Briefing (2/16/22)	Review and provide feedback	No	N/A
CAL FIRE	CAL FIRE San Luis Obispo County Duty Chief, N/A	Fire Chiefs and CAL FIRE Wildfire Briefing (2/16/22)	Review and provide feedback	No	N/A
CAL FIRE	Cal FIRE Shasta County, ECC, N/A	Fire Chiefs and CAL FIRE Wildfire Briefing (2/16/22)	Review and provide feedback	No	N/A
CAL FIRE	CAL FIRE Tuolumne County, N/A	Fire Chiefs and CAL FIRE Wildfire Briefing (2/16/22)	Review and provide feedback	No	N/A

TABLE 8-44:
STATE AND LOCAL AGENCY COLLABORATION(S)
(CONTINUED)

Name of State or Local Agency	Point of Contact and Information	Emergency Preparedness Plan Collaboration* – Last Version of Plan Agency Collaborated	Emergency Preparedness Plan Collaboration – Collaborative Role	Memorandum of Agreement (MOA)?	Brief Description of MOA
CAL FIRE	David Fulcher, Fire Chief	Fire Chiefs and CAL FIRE Wildfire Briefing (2/16/22)	Review and provide feedback	No	N/A
CAL FIRE	Dispatch CAL FIRE TCU, Local Cal Fire N/A	Fire Chiefs and CAL FIRE Wildfire Briefing (2/16/22)	Review and provide feedback	No	N/A
CAL FIRE	Dustin Hail, Unit Chief	Fire Chiefs and CAL FIRE Wildfire Briefing (2/16/22)	Review and provide feedback	No	N/A
CAL FIRE	Duty Chief, N/A	Fire Chiefs and CAL FIRE Wildfire Briefing (2/16/22)	Review and provide feedback	No	N/A
CAL FIRE	Eddy Moore, Local Cal Fire	Fire Chiefs and CAL FIRE Wildfire Briefing (2/16/22)	Review and provide feedback	No	N/A
CAL FIRE	Garrett Sjolund, Division Chief	Fire Chiefs and CAL FIRE Wildfire Briefing (2/16/22)	Review and provide feedback	No	N/A
CAL FIRE	George Gonzalez, Local Cal Fire	Fire Chiefs and CAL FIRE Wildfire Briefing (2/16/22)	Review and provide feedback	No	N/A
CAL FIRE	George Morris III, Local Cal Fire	Fire Chiefs and CAL FIRE Wildfire Briefing (2/16/22)	Review and provide feedback	No	N/A
CAL FIRE	Gratain Bidart, Acting Chief	Fire Chiefs and CAL FIRE Wildfire Briefing (2/16/22)	Review and provide feedback	No	N/A

TABLE 8-44:
STATE AND LOCAL AGENCY COLLABORATION(S)
(CONTINUED)

Name of State or Local Agency	Point of Contact and Information	Emergency Preparedness Plan Collaboration* – Last Version of Plan Agency Collaborated	Emergency Preparedness Plan Collaboration – Collaborative Role	Memorandum of Agreement (MOA)?	Brief Description of MOA
CAL FIRE	Ian Larkin, Local Cal Fire, N/A	Fire Chiefs and CAL FIRE Wildfire Briefing (2/16/22)	Review and provide feedback	No	N/A
CAL FIRE	Jesse Morris, Battalion Chief	Fire Chiefs and CAL FIRE Wildfire Briefing (2/16/22)	Review and provide feedback	No	N/A
CAL FIRE	Jim Hudson, Deputy Chief	Fire Chiefs and CAL FIRE Wildfire Briefing (2/16/22)	Review and provide feedback	No	N/A
CAL FIRE	John Slate, Duty Chief	Fire Chiefs and CAL FIRE Wildfire Briefing (2/16/22)	Review and provide feedback	No	N/A
CAL FIRE	Jon Woody, Battalion Chief	Fire Chiefs and CAL FIRE Wildfire Briefing (2/16/22)	Review and provide feedback	No	N/A
CAL FIRE	Ken Lowe, Division Chief	Fire Chiefs and CAL FIRE Wildfire Briefing (2/16/22)	Review and provide feedback	No	N/A
CAL FIRE	Kurt McCray, Local Cal Fire	Fire Chiefs and CAL FIRE Wildfire Briefing (2/16/22)	Review and provide feedback	No	N/A
CAL FIRE	LNU Dispatch Lake County, Dispatch, N/A	Fire Chiefs and CAL FIRE Wildfire Briefing (2/16/22)	Review and provide feedback	No	N/A
CAL FIRE	Mark Kendall, Chief of Northern Operations	Fire Chiefs and CAL FIRE Wildfire Briefing (2/16/22)	Review and provide feedback	No	N/A

TABLE 8-44:
STATE AND LOCAL AGENCY COLLABORATION(S)
(CONTINUED)

Name of State or Local Agency	Point of Contact and Information	Emergency Preparedness Plan Collaboration* – Last Version of Plan Agency Collaborated	Emergency Preparedness Plan Collaboration – Collaborative Role	Memorandum of Agreement (MOA)?	Brief Description of MOA
CAL FIRE	Matt Streck, Division Chief	Fire Chiefs and CAL FIRE Wildfire Briefing (2/16/22)	Review and provide feedback	No	N/A
CAL FIRE	Mike Blankenheim, Local Cal Fire	Fire Chiefs and CAL FIRE Wildfire Briefing (2/16/22)	Review and provide feedback	No	N/A
CAL FIRE	Mike Marcucci, Local Cal Fire, N/A	Fire Chiefs and CAL FIRE Wildfire Briefing (2/16/22)	Review and provide feedback	No	N/A
CAL FIRE	Mike Marcucci, Unit Chief	Fire Chiefs and CAL FIRE Wildfire Briefing (2/16/22)	Review and provide feedback	No	N/A
CAL FIRE	Mike van Loben Sels, Unit Chief	Fire Chiefs and CAL FIRE Wildfire Briefing (2/16/22)	Review and provide feedback	No	N/A
CAL FIRE	Nate Armstrong, Cal-Fire Unit Chief CZU	Fire Chiefs and CAL FIRE Wildfire Briefing (2/16/22)	Review and provide feedback	No	N/A
CAL FIRE	Nick Casci, Unit Chief	Fire Chiefs and CAL FIRE Wildfire Briefing (2/16/22)	Review and provide feedback	No	N/A
CAL FIRE	Patrick Purvis, Division Chief	Fire Chiefs and CAL FIRE Wildfire Briefing (2/16/22)	Review and provide feedback	No	N/A
CAL FIRE	Reno Ditullio Jr., Fire Chief	Fire Chiefs and CAL FIRE Wildfire Briefing (2/16/22)	Review and provide feedback	No	N/A

TABLE 8-44:
STATE AND LOCAL AGENCY COLLABORATION(S)
(CONTINUED)

Name of State or Local Agency	Point of Contact and Information	Emergency Preparedness Plan Collaboration* – Last Version of Plan Agency Collaborated	Emergency Preparedness Plan Collaboration – Collaborative Role	Memorandum of Agreement (MOA)?	Brief Description of MOA
CAL FIRE	Robert Withrow, Unit Chief	Fire Chiefs and CAL FIRE Wildfire Briefing (2/16/22)	Review and provide feedback	No	N/A
CAL FIRE	Ryan Woessner, Battalion Chief	Fire Chiefs and CAL FIRE Wildfire Briefing (2/16/22)	Review and provide feedback	No	N/A
CAL FIRE	Scott Lindgren, Local Cal Fire	Fire Chiefs and CAL FIRE Wildfire Briefing (2/16/22)	Review and provide feedback	No	N/A
CAL FIRE	Sean Norman, Division Chief	Fire Chiefs and CAL FIRE Wildfire Briefing (2/16/22)	Review and provide feedback	No	N/A
CAL FIRE	St. Helena Emergency Command Center, LNU Command Center	Fire Chiefs and CAL FIRE Wildfire Briefing (2/16/22)	Review and provide feedback	No	N/A
CAL FIRE	Steve Mueller, Battalion Chief	Fire Chiefs and CAL FIRE Wildfire Briefing (2/16/22)	Review and provide feedback	No	N/A
CAL FIRE	Steve Walker, Division Chief	Fire Chiefs and CAL FIRE Wildfire Briefing (2/16/22)	Review and provide feedback	No	N/A
Calaveras County	John Osbourn, OES Director	Regional Working Group: Central Valley (12/7/22)	Review and provide feedback	No	N/A
California Choinumni Tribal Project	Rosemary Smith, Tribal Chair	N/A	N/A	No	N/A
California Valley Miwok Tribe	Sylvia Burley, Chairperson	N/A	N/A	No	N/A

TABLE 8-44:
STATE AND LOCAL AGENCY COLLABORATION(S)
(CONTINUED)

Name of State or Local Agency	Point of Contact and Information	Emergency Preparedness Plan Collaboration* – Last Version of Plan Agency Collaborated	Emergency Preparedness Plan Collaboration – Collaborative Role	Memorandum of Agreement (MOA)?	Brief Description of MOA
Chaushila Yokuts	Jerry Brown, Chairman	N/A	N/A	No	N/A
Chicken Ranch Rancheria	LeeAnn Hatton, Assistant Tribal Administrator	Regional Working Group: Central Valley (12/7/22)	Review and provide feedback	No	N/A
Cloverdale Rancheria	Maria Elliott, Tribal Secretary	N/A	N/A	No	N/A
Coastal Band of the Chumash Nation	Mia Lopez, Chairperson	N/A	N/A	No	N/A
Coastanoan Oholone Rumsen-Mutsen Tribe	Patrick Orozco, General	N/A	N/A	No	N/A
Cold Springs Rancheria	Helena Alarcon, Chairwoman	N/A	N/A	No	N/A
Colusa County	Janice Bell, OES Coordinator	Regional Working Group: North Valley/Sierra (12/7/22)	Review and provide feedback	No	N/A
Colusa County	Russ Jones, OES	Regional Working Group: North Valley/Sierra (12/7/22)	Review and provide feedback	No	N/A
Colusa County	Cameron Bardwell, OES	Regional Working Group: North Valley/Sierra (12/7/22)	Review and provide feedback	No	N/A
Contra Costa County	Duty Officer (24/7), On Call contact	Regional Working Group: Bay Area (12/9/22)	Review and provide feedback	No	N/A
Contra Costa County	Rick Kovar, OES Director	Regional Working Group: Bay Area (12/9/22)	Review and provide feedback	No	N/A

TABLE 8-44:
STATE AND LOCAL AGENCY COLLABORATION(S)
(CONTINUED)

Name of State or Local Agency	Point of Contact and Information	Emergency Preparedness Plan Collaboration* – Last Version of Plan Agency Collaborated	Emergency Preparedness Plan Collaboration – Collaborative Role	Memorandum of Agreement (MOA)?	Brief Description of MOA
Cortina Rancheria	Charlie Wright, Chairperson	Regional Working Group: North Valley/Sierra (12/7/22)	Review and provide feedback	No	N/A
Coyote Valley Band of Pomo	Michael Hunter, Council Chairman	Regional Working Group: North Coast (12/8/22)	Review and provide feedback	No	N/A
Dry Creek Rancheria	Matt Epstein, Fire Chief	Regional Working Group: North Coast (12/8/22)	Review and provide feedback	No	N/A
Dumna Wo-Wah Tribal Government	Robert Ledger, Chairperson	N/A	N/A	No	N/A
Dunlap Band of Mono Indians	Florence Dick, Tribal Secretary	Regional Working Group: Central Valley (12/7/22)	Review and provide feedback	No	N/A
Dunlap Band of Mono Indians Historical Preservation Society	Mandy Marine, President	Regional Working Group: Central Valley (12/7/22)	Review and provide feedback	No	N/A
El Dorado County	El Dorado General	Regional Working Group: North Valley/Sierra (12/7/22)	Review and provide feedback	No	N/A
El Dorado County	Moke Auwae, OES	Regional Working Group: North Valley/Sierra (12/7/22)	Review and provide feedback	No	N/A
Elem Indian Colony	Agustin Garcia, Chairman	N/A	N/A	No	N/A
Enterprise Rancheria	Tony Whiddon, Casino Director of Security	Regional Working Group: North Valley/Sierra (12/7/22)	Review and provide feedback	No	N/A

TABLE 8-44:
STATE AND LOCAL AGENCY COLLABORATION(S)
(CONTINUED)

Name of State or Local Agency	Point of Contact and Information	Emergency Preparedness Plan Collaboration* – Last Version of Plan Agency Collaborated	Emergency Preparedness Plan Collaboration – Collaborative Role	Memorandum of Agreement (MOA)?	Brief Description of MOA
Fresno County	Brandon Pursell Sheriff	Regional Working Group: Central Valley (12/7/22)	Review and provide feedback	No	N/A
Fresno County	Gabriel De La Cerda , Assistant OES Director	Regional Working Group: Central Valley (12/7/22)	Review and provide feedback	No	N/A
Glenn County	Amy Travis, OES Director	Regional Working Group: North Valley/Sierra (12/7/22)	Review and provide feedback	No	N/A
Graton Rancheria	Greg Sarris, Chairman	Regional Working Group: North Coast (12/8/22)	Review and provide feedback	No	N/A
Greenville Rancheria	Ntango (Desi) Banani, Medical Director	Regional Working Group: North Valley/Sierra (12/7/22)	Review and provide feedback	No	N/A
Grindstone Rancheria	Ronald Kirk, Chairman	N/A	N/A	No	N/A
Guidiville Rancheria	Meyo Marrufo, EPA Director	N/A	N/A	No	N/A
Haslett Basin Traditional Committee	Martin Davis, Chairman	N/A	N/A	No	N/A
Honey Lake Maidu	Ronald Morales, General	N/A	N/A	No	N/A
Hoopa Valley Tribe	Joe Davis, Chairman	Regional Working Group: North Coast (12/8/22)	Review and provide feedback	No	N/A
Hopland Reservation	Sonny Elliott, Chairperson	Regional Working Group: North Coast (12/8/22)	Review and provide feedback	No	N/A

TABLE 8-44:
STATE AND LOCAL AGENCY COLLABORATION(S)
(CONTINUED)

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Humboldt County	Ryan Derby, OES Director	Regional Working Group: North Coast (12/8/22)	Review and provide feedback	No	N/A
Indian Canyon Mutsun Band of Costanoan	Ann Marie Sayers, Chairperson	Regional Working Group: South Bay/Central Coast (12/8/22)	Review and provide feedback	No	N/A
Ione Band of Miwok Indians	Sara Dutschke Setshwaelo, Chairperson (24-hour)	N/A	N/A	No	N/A
Jackson Rancheria	Larry Forst, Facilities Director	N/A	N/A	No	N/A
Karuk Tribe	Jacqueline Nushi, Emergency Manager	Regional Working Group: North Coast (12/8/22)	Review and provide feedback	No	N/A
Kawaiisu Tribe	David Robinson, Chairperson	N/A	N/A	No	N/A
Kern County	Georgianna Armstrong, OES Director	Regional Working Group: Central Valley (12/7/22)	Review and provide feedback	No	N/A
Kern Valley Indian Council	Robert Robinson, Historic Preservation Officer	N/A	N/A	No	N/A
Kings County	German Ortiz, OES	N/A	N/A	No	N/A
Lake County	Gavin Wells, OES	Regional Working Group: North Coast (12/8/22)	Review and provide feedback	No	N/A
Lake County	Leah Sautelet, OES Manager	Regional Working Group: North Coast (12/8/22)	Review and provide feedback	No	N/A

TABLE 8-44:
STATE AND LOCAL AGENCY COLLABORATION(S)
(CONTINUED)

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Lassen County	Silas Rojas, OES Director	Regional Working Group: North Valley/Sierra (12/7/22)	Review and provide feedback	No	N/A
Laytonville Rancheria	Fred Simmons, EPA Tech	N/A	N/A	No	N/A
Lower Lake Rancheria	Darin Beltran, Chairman	N/A	N/A	No	N/A
Lytton Rancheria	Lisa Miller, Tribal Administrator	Regional Working Group: Bay Area (12/9/22)	Review and provide feedback	No	N/A
Madera County	Joseph Wilder, OES Coordinator/Sergeant	Regional Working Group: Central Valley (12/7/22)	Review and provide feedback	No	N/A
Madera County	Tyson Pogue, OES Director/Sheriff	Regional Working Group: Central Valley (12/7/22)	Review and provide feedback	No	N/A
Manchester-Point Arena Rancheria	Linda Lawson, Tribal Council	N/A	N/A	No	N/A
Marin County	Chris Reilly, OES Manager	Regional Working Group: North Coast (12/8/22)	Review and provide feedback	No	N/A
Marin County	Marin Duty Officer Mailbox, on Call contact	Regional Working Group: North Coast (12/8/22)	Review and provide feedback	No	N/A
Marin County	Woody Baker-Cohn, OES Assist. Manager	Regional Working Group: North Coast (12/8/22)	Review and provide feedback	No	N/A
Mariposa County	Jeremy Briese, OES Director/Sheriff	Regional Working Group: Central Valley (12/7/22)	Review and provide feedback	No	N/A
Mariposa County	Wes Smith, OES Coordinator/Sergeant	Regional Working Group: Central Valley (12/7/22)	Review and provide feedback	No	N/A

TABLE 8-44:
STATE AND LOCAL AGENCY COLLABORATION(S)
(CONTINUED)

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Mechoopda Indian Tribe	Mark Alabanza, Tribal Administrative Officer	N/A	N/A	No	N/A
Mendocino County	Garrett James, OES	Regional Working Group: North Coast (12/8/22)	Review and provide feedback	No	N/A
Mendocino County	Brentt Blaser, OES Director	Regional Working Group: North Coast (12/8/22)	Review and provide feedback	No	N/A
Merced County	Adam Amaral, OES Coordinator	Regional Working Group: Central Valley (12/7/22)	Review and provide feedback	No	N/A
Middletown Rancheria	Jose Simon, Chairman	Regional Working Group: North Coast (12/8/22)	Review and provide feedback	No	N/A
Mishewal-Wappo of Alexander Valley	Scott Gabaldon, Chairperson	N/A	N/A	No	N/A
Monterey County	Duty Officer (24/7), On Call contact	Regional Working Group: South Bay/Central Coast (12/8/22)	Review and provide feedback	No	N/A
Monterey County	Gerry Malais, OES Director	Regional Working Group: South Bay/Central Coast (12/8/22)	Review and provide feedback	No	N/A
Monterey County	Kelsey Scanon OES	Regional Working Group: South Bay/Central Coast (12/8/22)	Review and provide feedback	No	N/A
Monterey County	Justin Lin Monterey County OES	Regional Working Group: South Bay/Central Coast (12/8/22)	Review and provide feedback	No	N/A

TABLE 8-44:
STATE AND LOCAL AGENCY COLLABORATION(S)
(CONTINUED)

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Mooretown Rancheria	Ronald Butz, Tribal Ops	Regional Working Group: North Valley/Sierra (12/7/22)	Review and provide feedback	No	N/A
Muwekma Ohlone Indian Tribe	Monica Arellano, Vice Chairwoman	N/A	N/A	No	N/A
Napa County	Leah Greenbaum, OES	Regional Working Group: North Coast (12/8/22)	Review and provide feedback	No	N/A
Napa County	Kerry Whitney, County Risk Manager	Regional Working Group: North Coast (12/8/22)	Review and provide feedback	No	N/A
Nevada County	Steve Monaghan, OES	Regional Working Group: North Valley/Sierra (12/7/22)	Review and provide feedback	No	N/A
Nevada County	Paul Cummings, OES Deputy Director	Regional Working Group: North Valley/Sierra (12/7/22)	Review and provide feedback	No	N/A
Nor-Rel-Muk Nation	Marilyn Delgado, Chairperson	N/A	N/A	No	N/A
North Fork Rancheria	Maryann McGovran, Treasurer	Regional Working Group: Central Valley (12/7/22)	Review and provide feedback	No	N/A
Northern Band of Mono Yokuts	Delaine Bill, Chairman	N/A	N/A	No	N/A
Noyo River Indian Community	Tribal Administration, General	N/A	N/A	No	N/A
Ohlone Indian Tribe	Andrew Galvan, General	N/A	N/A	No	N/A

TABLE 8-44:
STATE AND LOCAL AGENCY COLLABORATION(S)
(CONTINUED)

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Paskenta Rancheria	Mike Foss, Security Manager	N/A	N/A	No	N/A
Picayune Rancheria (Chukchansi Tribe)	John Saucedo, Cultural Resource Monitor	Regional Working Group: Central Valley (12/7/22)	Review and provide feedback	No	N/A
Pinoleville Reservation	Leona Williams, Chairperson	N/A	N/A	No	N/A
Pit River Tribes	Agnes Gonzalez, Chairwoman	Regional Working Group: North Valley/Sierra (12/7/22)	Review and provide feedback	No	N/A
Placer County	General, OES General Mail Box	Regional Working Group: North Valley/Sierra (12/7/22)	Review and provide feedback	No	N/A
Plumas County	Pam Courtright, OES Coordinator	Regional Working Group: North Valley/Sierra (12/7/22)	Review and provide feedback	No	N/A
Potter Valley Tribe	Salvador Rosales, Tribal Chairman	N/A	N/A	No	N/A
Redding Rancheria	Carlos Wilson , Maintenance Supervisor	Regional Working Group: North Valley/Sierra (12/7/22)	Review and provide feedback	No	N/A
Redwood Valley Rancheria	Mary Camp, Tribal Administrator	N/A	N/A	No	N/A
Robinson Rancheria	Esther Stauffer, Tribal Administrator	Regional Working Group: North Coast (12/8/22)	Review and provide feedback	No	N/A
Rohnerville Rancheria	Josefina Cortez, Tribal Chairwoman	N/A	N/A	No	N/A

TABLE 8-44:
STATE AND LOCAL AGENCY COLLABORATION(S)
(CONTINUED)

Name of State or Local Agency	Point of Contact and Information	Emergency Preparedness Plan Collaboration* – Last Version of Plan Agency Collaborated	Emergency Preparedness Plan Collaboration – Collaborative Role	Memorandum of Agreement (MOA)?	Brief Description of MOA
Round Valley Reservation	Michael Henry, Chief of Police	Regional Working Group: North Coast (12/8/22)	Review and provide feedback	No	N/A
Sacramento County	Matthew Hawkins, OES Director	Regional Working Group: North Valley/Sierra (12/7/22)	Review and provide feedback	No	N/A
Sacramento County	Steve Cantelme, OES	Regional Working Group: North Valley/Sierra (12/7/22)	Review and provide feedback	No	N/A
Salinan Tribe of Monterey, San Luis Obispo and San Benito Counties	John Burch, Chairperson	N/A	N/A	No	N/A
San Benito County	Kris Mangano, Emergency Services Manager	Regional Working Group: South Bay/Central Coast (12/8/22)	Review and provide feedback	No	N/A
San Benito County	Madison Mitchell, Emergency Services Coordinator	Regional Working Group: South Bay/Central Coast (12/8/22)	Review and provide feedback	No	N/A
San Francisco County	Adrienne Bechelli, Deputy Director	Regional Working Group: Bay Area (12/9/22)	Review and provide feedback	No	N/A
San Francisco County	DEM Duty Officer, On Call contact	Regional Working Group: Bay Area (12/9/22)	Review and provide feedback	No	N/A
San Francisco County	Francis Zamora, Chief of Staff	Regional Working Group: Bay Area (12/9/22)	Review and provide feedback	No	N/A
San Francisco County	Jodi Traversaro, UASI Liaison	Regional Working Group: Bay Area (12/9/22)	Review and provide feedback	No	N/A

TABLE 8-44:
STATE AND LOCAL AGENCY COLLABORATION(S)
(CONTINUED)

Name of State or Local Agency	Point of Contact and Information	Emergency Preparedness Plan Collaboration* – Last Version of Plan Agency Collaborated	Emergency Preparedness Plan Collaboration – Collaborative Role	Memorandum of Agreement (MOA)?	Brief Description of MOA
San Francisco County	Victor Lim, External Affairs Officer	Regional Working Group: Bay Area (12/9/22)	Review and provide feedback	No	N/A
San Joaquin County	Tiffany Heyer, OES Director of Emergency Services	Regional Working Group: Central Valley (12/7/22)	Review and provide feedback	No	N/A
San Luis Obispo County	Duty Officer, Duty Officer	Regional Working Group: South Bay/Central Coast (12/8/22)	Review and provide feedback	No	N/A
San Luis Obispo County	Joe Guzzardi, OES	Regional Working Group: South Bay/Central Coast (12/8/22)	Review and provide feedback	No	N/A
San Luis Obispo County	Scotty Jalbert, Emergency Services Manager	Regional Working Group: South Bay/Central Coast (12/8/22)	Review and provide feedback	No	N/A
San Luis Obispo County Chumash Council	Mark Vigil, Chairperson	N/A	N/A	No	N/A
San Mateo County	Don Mattie, Director	Regional Working Group: Bay Area (12/9/22)	Review and provide feedback	No	N/A
San Mateo County	Jeff Norris, DEM Coordinator	Regional Working Group: Bay Area (12/9/22)	Review and provide feedback	No	N/A
Santa Barbara County	Kelly Hubbard, OEM Director	Regional Working Group: South Bay/Central Coast (12/8/22)	Review and provide feedback	No	N/A
Santa Clara County	Dana Reed, Director	Regional Working Group: South Bay/Central Coast (12/8/22)	Review and provide feedback	No	N/A

TABLE 8-44:
STATE AND LOCAL AGENCY COLLABORATION(S)
(CONTINUED)

Name of State or Local Agency	Point of Contact and Information	Emergency Preparedness Plan Collaboration* – Last Version of Plan Agency Collaborated	Emergency Preparedness Plan Collaboration – Collaborative Role	Memorandum of Agreement (MOA)?	Brief Description of MOA
Santa Clara County	Darrell Ray Jr., Deputy Director	Regional Working Group: South Bay/Central Coast (12/8/22)	Review and provide feedback	No	N/A
Santa Cruz County	David Reid, Director	Regional Working Group: South Bay/Central Coast (12/8/22)	Review and provide feedback	No	N/A
Santa Cruz County	Michael Beaton, Director General Services	Regional Working Group: South Bay/Central Coast (12/8/22)	Review and provide feedback	No	N/A
Santa Rosa Rancheria	Rueben Barrios, Chairperson	N/A	N/A	No	N/A
Santa Cruz County	Lisa Ehret, OES	Regional Working Group: South Bay/Central Coast (12/8/22)	Review and provide feedback	No	N/A
Santa Cruz County	Michael Bennett, OES	Regional Working Group: South Bay/Central Coast (12/8/22)	Review and provide feedback	No	N/A
Santa Ynez Band of Chumash	Daune Dowell, Risk Manager	Regional Working Group: South Bay/Central Coast (12/8/22)	Review and provide feedback	No	N/A
Scotts Valley Band of Pomo	Sorhna Li, CFO/Interim TANF ED	N/A	N/A	No	N/A
Shasta County	Dave Renfer, OES Officer	Regional Working Group: North Valley/Sierra (12/7/22)	Review and provide feedback	No	N/A

**TABLE 8-44:
STATE AND LOCAL AGENCY COLLABORATION(S)
(CONTINUED)**

Name of State or Local Agency	Point of Contact and Information	Emergency Preparedness Plan Collaboration* – Last Version of Plan Agency Collaborated	Emergency Preparedness Plan Collaboration – Collaborative Role	Memorandum of Agreement (MOA)?	Brief Description of MOA
Shasta County	Rob Sandbloom, OES Director	Regional Working Group: North Valley/Sierra (12/7/22)	Review and provide feedback	No	N/A
Shebelna Band of Mendocino Coast Pomo Indians	Shirley Harbor, Chairperson	N/A	N/A	No	N/A
Sherwood Valley Band of Pomo	Melanie Rafnan, Tribal Chairperson	N/A	N/A	No	N/A
Shingle Springs Rancheria	Regina Cuellar, Chairwoman	Regional Working Group: North Valley/Sierra (12/7/22)	Review and provide feedback	No	N/A
Sierra County	Lee Brown, OES Director	Regional Working Group: North Valley/Sierra (12/7/22)	Review and provide feedback	No	N/A
Siskiyou County	Bryan Schenone, OES Director	Regional Working Group: North Coast (12/8/22)	Review and provide feedback	No	N/A
Solano County	Donald Ryan, OES Director	Regional Working Group: North Valley/Sierra (12/7/22)	Review and provide feedback	No	N/A
Sonoma County	Christopher Godley, DEM Director	Regional Working Group: North Coast (12/8/22)	Review and provide feedback	No	N/A
Sonoma County	Emergency Management, DEM General Inbox	Regional Working Group: North Coast (12/8/22)	Review and provide feedback	No	N/A
Sonoma County	Jeff Duvall, DEM Deputy Director	Regional Working Group: North Coast (12/8/22)	Review and provide feedback	No	N/A

TABLE 8-44:
STATE AND LOCAL AGENCY COLLABORATION(S)
(CONTINUED)

Name of State or Local Agency	Point of Contact and Information	Emergency Preparedness Plan Collaboration* – Last Version of Plan Agency Collaborated	Emergency Preparedness Plan Collaboration – Collaborative Role	Memorandum of Agreement (MOA)?	Brief Description of MOA
Sonoma County	Sam Wallis, DEM Community Warning	Regional Working Group: North Coast (12/8/22)	Review and provide feedback	No	N/A
Stanislaus County	Richard Murdock, Fire Marshall	Regional Working Group: Central Valley (12/7/22)	Review and provide feedback	No	N/A
Stanislaus County	Shannon Williams, OES	Regional Working Group: Central Valley (12/7/22)	Review and provide feedback	No	N/A
Stanislaus County	Ron Reid, County OES	Regional Working Group: Central Valley (12/7/22)	Review and provide feedback	No	N/A
Stewarts Point Rancheria	Enrique Sanchez, Emergency Planner	N/A	N/A	No	N/A
Strawberry Valley Rancheria	Cathy Bishop, Chairperson	N/A	N/A	No	N/A
Susanville Indian Rancheria	Arian Hart, Tribal Chairman	N/A	N/A	No	N/A
Sutter County	Zach Hamill, OES Director	Regional Working Group: Central Valley (12/7/22)	Review and provide feedback	No	N/A
Table Mountain Rancheria	Leanne Walker-Grant, Chairperson	N/A	N/A	No	N/A
Tehama County	Andy Houghtby, OES Director	Regional Working Group: North Valley/Sierra (12/7/22)	Review and provide feedback	No	N/A
Tejon Indian Tribe	Octavio Eschobebo, Chairperson	Regional Working Group: Central Valley (12/7/22)	Review and provide feedback	No	N/A
The Mono Nation	Dorothy Sherman, General	Regional Working Group: Central Valley (12/7/22)	Review and provide feedback	No	N/A

TABLE 8-44:
STATE AND LOCAL AGENCY COLLABORATION(S)
(CONTINUED)

Name of State or Local Agency	Point of Contact and Information	Emergency Preparedness Plan Collaboration* – Last Version of Plan Agency Collaborated	Emergency Preparedness Plan Collaboration – Collaborative Role	Memorandum of Agreement (MOA)?	Brief Description of MOA
Traditional Choinumni Tribe (East of Kings River)	David Alvarez, Chairman	N/A	N/A	No	N/A
Trina Marine Ruano Family	Ramona Garibay, Representative	N/A	N/A	No	N/A
Trinidad Rancheria	Jaque Hostler-Carmesin, Chief Executive Officer	N/A	N/A	No	N/A
Trinity County	Mike Cottone, OES	Regional Working Group: North Coast (12/8/22)	Review and provide feedback	No	N/A
Tsungwe Council	James Ammon, Chairman	N/A	N/A	No	N/A
Tubatulabal Tribe	Robert Gomez, Chairman	N/A	N/A	No	N/A
Tulare County	Andrew Lockman, Emergency Services Manager	Regional Working Group: Central Valley (12/7/22)	Review and provide feedback	No	N/A
Tule River Indian Tribe	Joe Boy Perez, Director of Emergency Management	N/A	N/A	No	N/A
Tuolumne Band of Me-Wuk Indians	Andrea Reich, Chairwoman	Regional Working Group: Central Valley (12/7/22)	Review and provide feedback	No	N/A
Tuolumne County	Dore Bietz, OES Coordinator	Regional Working Group: Central Valley (12/7/22)	Review and provide feedback	No	N/A
United Auburn Indian Community	Brian Guth, Interim Tribal Administrator	Regional Working Group: North Valley/Sierra (12/7/22)	Review and provide feedback	No	N/A

TABLE 8-44:
STATE AND LOCAL AGENCY COLLABORATION(S)
(CONTINUED)

Name of State or Local Agency	Point of Contact and Information	Emergency Preparedness Plan Collaboration* – Last Version of Plan Agency Collaborated	Emergency Preparedness Plan Collaboration – Collaborative Role	Memorandum of Agreement (MOA)?	Brief Description of MOA
Upper Lake Rancheria	Anthony Arroyo, Tribal Administrator	Regional Working Group: North Coast (12/8/22)	Review and provide feedback	No	N/A
Wailaki Tribe	Louis Hoaglin, Chairperson	N/A	N/A	No	N/A
Washoe Tribe	Serrell Smokey, Chairperson	N/A	N/A	No	N/A
Wilton Rancheria	Jesus Tarango Jr, Chairman	N/A	N/A	No	N/A
Winnemem Wintu Tribe	Caleen Sisk, Spiritual Leader	N/A	N/A	No	N/A
Wintu Tribe of Northern California	Wade McMaster, Chairman	N/A	N/A	No	N/A
Wiyot Tribe	Theodore Hernandez, Tribal Chairman	N/A	N/A	No	N/A
Wukchumni Tribal Council	Darlene Franco, Chairperson	N/A	N/A	No	N/A
Wuksachi Indian Tribe	Kenneth Woodrow, Chairman	N/A	N/A	No	N/A
Xolon Salinan Tribe	Johnny Eddy, Chairperson	N/A	N/A	No	N/A
Yocha Dehe Wintun Nation	Becky Ramirez, Fire Chief	Regional Working Group: North Valley/Sierra (12/7/22)	Review and provide feedback	No	N/A

TABLE 8-44:
STATE AND LOCAL AGENCY COLLABORATION(S)
(CONTINUED)

Name of State or Local Agency	Point of Contact and Information	Emergency Preparedness Plan Collaboration* – Last Version of Plan Agency Collaborated	Emergency Preparedness Plan Collaboration – Collaborative Role	Memorandum of Agreement (MOA)?	Brief Description of MOA
Yolo County	Kristin Weivoda, OES	Regional Working Group: North Valley/Sierra (12/7/22)	Review and provide feedback	No	N/A
Yuba County	John Stone, OES Deputy Director	Regional Working Group: North Valley/Sierra (12/7/22)	Review and provide feedback	No	N/A
Yuba County	Oscar Marin, OES Director	Regional Working Group: North Valley/Sierra (12/7/22)	Review and provide feedback	No	N/A
Yurok Tribe	Amos Pole, Deputy OES Director	Regional Working Group: North Coast (12/8/22)	Review and provide feedback	No	N/A

Confidential contact information has been removed from this public version of Table 8-46. A copy of this table with contact information is available in Appendix I_CONF.

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
City	City of Amador	Joyce Davidson, City Clerk	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of American Canyon	Jason Holley, City Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Anderson	Jeff Kiser, City Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Anderson	Mike Jensen, Public Works Superintendent	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Anderson	Nick Jones, Chief Treatment Plant Operator	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Anderson	Peter Wickenheiser, Deputy Public Works Director	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
City	City of Anderson	Steve Blunk, Lieutenant	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Anderson	Steve Lowe, Fire Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Angels Camp	Alvin Broglio, Council Member	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Angels Camp	Melissa Eads, City Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Angels Camp	Ron Bernal, City Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Arcata	Karen Diemer, City Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Arvin	Mr. Jerry Breckinridge, City Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Atherton	David Huynh, Public Works Maintenance Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Atherton	George Rodericks, City Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
City	City of Atherton	Robert Ovadia, Public Works Director	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Atherton	Steve McCulley, Police Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Atwater	Lori Waterman, City Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Auburn	Dave Spencer, Fire Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Avenal	City Administration	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Bakersfield	City Administration Bakersfield, City Hall	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Belmont	Afshin Oskoui, City Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Belvedere	Craig Middleton, City Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Benicia	Sarah Grebe, Assistant City Manager,	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY
(CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
City	City of Benicia	Steve Young, Mayor	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Benicia	Will Tarbox, Public Works Director	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Berkeley	Dee Williams-Ridley, City Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Berkeley	Katherine Hawn, Emergency Services Coordinator	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Blue Lake	Amanda Mager, City Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Blue Lake	Glenn Bernald, Public Works Director	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Brentwood	Gustavo Vina, City Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Brentwood	Miki Tsubota, Public Works Director	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Brentwood	Robert Taylor, Mayor	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
City	City of Brisbane	Clayton Holstine, City Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Brisbane	Randy Breault, Director	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Brisbane	Stuart Schillinger, Deputy City Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Burlingame	Lisa Goldman, City Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Calistoga	Chris Canning, Mayor	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Calistoga	Zach Tusinger, Interim City Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Capitola	CaKristen Petersen, Councilmember	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Capitola	City Administration Capitola, City Hall	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Capitola	Jacques Bertrand, Councilmember	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY
(CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
City	City of Capitola	Jamie Goldstein, City Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Capitola	Margaux Keiser, Councilmember	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Capitola	Sam Storey, Councilmember	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Capitola	Yvette Brooks, Councilmember	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Carmel-by-the-Sea	Bob Harary, Public Works Director	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Carmel-by-the-Sea	Chip Rerig, City Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Carmel-by-the-Sea	City Administration Carmel-by-the-sea, City Hall	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Chico	Andrew Coolidge, Mayor	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Chico	Kasey Reynolds, Vice-Mayor	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY
(CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
City	City of Chico	Mr. Mark Orme, City Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Chowchilla	City Administrator Chowchilla, City Hall	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Chowchilla	Rod Pruett, City Administrator	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Clayton	Joe Sbranti, Interim City Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Clayton	Keith Haydon, Mayor	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Clearlake	Alan Flora, City Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Clearlake	Dirk Slooten, Mayor	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Cloverdale	David Kelley, City Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Cloverdale	Gus Wolter, Mayor	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
City	City of Cloverdale	Jason Turner, Mayor	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Cloverdale	Kevin Thompson, Assistant City Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Cloverdale	Mark Rincon, Director of Public Works	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Cloverdale	Marta Cruz, Councilmember	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Cloverdale	Todd Lands, Vice Mayor	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Clovis	Drew Bessinger, Council Member	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Clovis	Mr. Luke Serpa, City Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Coalinga	Melissa Trejo, City Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Colfax	Wes Heathcock, City Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
City	City of Colfax	William Stockwin, Mayor	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Concord	Valerie Barone, City Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Corcoran	City Administration Corcoran, City Hall	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Corning	Kristina Miller, City Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Corte Madera	Todd Cusimano, Town Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Cotati	Craig Scott, Director of Public Works	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Cotati	Michael Parish, Police Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Cotati	Mr. Damien O'Bid, City Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Cupertino	Deborah Feng, City Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
City	City of Daly City	Leilani Ramos, Senior Management Analyst	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Daly City	Shawnna Maltbie, City Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Daly City	Stephen Stolte, Assistant to the City Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Danville	Joe Calabrigo, City Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Danville	Karen Stepper, Councilmember	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Danville	Lisa Blackwell, Vice Mayor	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Del Rey Oaks	Alison Kerr, Mayor	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Del Rey Oaks	Dino Pick, City Manager/Administrator	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Del Rey Oaks	John Gaglioti, Councilmember	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
City	City of Del Rey Oaks	Karen Minami, Deputy City Clerk	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Del Rey Oaks	Patricia Lintell, Councilmember	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Dinuba	City Administration Dinuba, City Hall	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Dos Palos	Debbie Orlando, Councilmember	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Dublin	Colleen Tribby, Assistant City Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Dublin	John Stefanski, Assistant to City Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Dublin	Linda Smith, City Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of East Palo Alto	City Administration East Palo Alto, City Hall	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of East Palo Alto	Sean Charpentier, Interim City Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
City	City of El Cerrito	City Administration El Cerrito, City Hall	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Emeryville	Christine Daniel, City Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Fairfax	Garrett Toy, Town Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Fairfield	Harry Price, Mayor	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Fairfield	Stefan Chatwin, City Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Ferndale	Bret Smith, Police Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Ferndale	Delbiaggio Daniel, Fire Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Ferndale	Jay Parrish, City Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Firebaugh	Ben Gallegos, City Manager, Designated POC	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
City	City of Fort Bragg	Ms. Tabatha Miller, City Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Fortuna	Merritt Perry, City Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Foster City	Dante Hall, Assistant City Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Fowler	Jeannie Davis, City Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Fremont	City Administration City Leadership, City Leadership	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Fremont	Lily Mei, Mayor	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Fresno	Facility Services Fresno County, Facility Services	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Fresno	Jerry Dyer, Mayor	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Fresno	Thomas Esqueda, City Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY
(CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
City	City of Gilroy	Andrew Young, Emergency Services and Volunteer Coordinator	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Gilroy	Jimmy Forbis, City Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Gilroy	Marie Blankley, City Councilmember	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Gilroy	Rachelle Bedell, Community Engagement	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Gonzales	City Administration Gonzales, City Hall	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Gonzales	Liz Silva, Councilmember	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Gonzales	Lorraine Worthy, Councilmember	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Gonzales	Paul Miller, Councilmember	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Gonzales	Rene Mendez, City Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
City	City of Gonzales	Scott Funk, Mayor Pro Tem	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Grass Valley	Ben Aguilar, Mayor	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Grass Valley	Timothy Kiser, City Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Greenfield	Angela Untalon, Councilmember	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Greenfield	Bob White, Councilmember	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Greenfield	Drew Tipton, Councilmember	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Greenfield	Lance Walker, Mayor	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Greenfield	Paul Wood, City Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Greenfield	Yanely Martinez, Mayor Pro Tem	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
City	City of Gridley	Bruce Johnson, Mayor	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Gridley	Mike Farr, Vice-Mayor	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Gridley	Rodney Harr, Interim City Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Gustine	Douglas Dunford, City Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Half Moon Bay	Bob Nisbet, City Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Half Moon Bay	Corie Stocker, Management Analyst	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Hanford	City Administration Hanford, City Hall	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Hayward	Barbara Halliday, Mayor	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Hayward	Bert Weiss, Utilities Operations & Maintenance Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

**TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY
(CONTINUED)**

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
City	City of Healdsburg	Andrew Sturmfels, Director Of Administrative Services	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Healdsburg	Heather Ippoliti, Finance Director	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Healdsburg	Jaime Licea, Parks & Open Space Superintendent	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Healdsburg	Jarrod Dericco, Public Works Superintendent	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Healdsburg	Jeff Kay, City Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Healdsburg	Larry Zimmer, Public Works Director	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Healdsburg	Malinalli Lopez, Public Information Officer	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Healdsburg	Mark Themig, Community Services	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Healdsburg	Rob Scates, Water/Wastewater Superintendent	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY
(CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
City	City of Healdsburg	Terry Crowley, Utility Director	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Healdsburg	Todd Woolman, Electric Superintendent	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Hercules	Chris Kelley, General	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Hercules	David Biggs, City Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Hillsborough	Ann Ritzma, Town Manage	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Hillsborough	Doug Davis, General	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Hillsborough	Paul Willis, Public Works Director	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Hollister	Brett Miller, City Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Hollister	City Administration Hollister, City Hall	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
City	City of Hollister	Honor Spencer, Councilmember	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Hollister	Ignacio Velazquez, Mayor	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Hollister	Rick Perez, Councilmember	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Hollister	Rolan Resendiz, Councilmember	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Hollister	Tim Burns, Councilmember	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Huron	Jack Castro, City Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Ione	Lori McGraw, City Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Ione	Stacy Rhoades, City Council	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Jackson	Bree Wilder, Public Works Foreman	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
City	City of Jackson	Robert Stimpson, Mayor	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Jackson	Yvonne Kimball, City Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Kerman	John Jansons, City Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of King City	Carlos DeLeon, Councilmember	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of King City	Carlos Victoria, Mayor Pro Tem,	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of King City	Darlene Acosta, Councilmember	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of King City	Mike LeBarre, Mayor	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of King City	Mr. Steven Adams (Monterey), City Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of King City	Robert Cullen, Councilmember	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
City	City of Kingsburg	Alexander Henderson, City Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Lafayette	Jeff Heyman, Communications Analyst	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Lafayette	Mike Anderson, Mayor	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Lafayette	Niroop Srivastsa, City Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Lafayette	Suzanne Iarla, Communications Analyst/Public Information Officer	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Lakeport	Kenneth Parlet, Mayor	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Lakeport	Kevin Ingram, City Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Lakeport	Ron Ladd, Public Works Superintendent	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
City	City of Larkspur	Dan Schwarz, City Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Lathrop	Steve Salvatore, City Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Lemoore	City Administration Lemoore, City Hall	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Lincoln	Mrs. Jennifer Hanson, Interim City Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Livermore	Herbert Cole, Emergency Services Director	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Livermore	John Marchand, Mayor	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Livermore	Marc Roberts, City Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Livingston	Jose Ramirez, City Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Livingston	Nick Jones, MOT Director	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
City	City of Loomis	Sean Rabe, Town Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Los Altos	Chris Jordan, City Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Los Altos Hills	Carl Cahill, City Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Los Altos Hills	Ms. Marsha Hovey, EMS Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Los Altos Hills	Nichol Bowersox, Public Works Director	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Los Banos	Josh Pinheiro, City Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Los Gatos	Arn Andrews, Assistant Town Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Los Gatos	City Administration Los Gatos, Community Outreach	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Los Gatos	Laurel Prevetti, City Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
City	City of Los Gatos	Matt Morely, Public Works Director	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Madera	Andrew Medellin, Mayor	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Madera	Mr. Arnoldo Rodriguez, City Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Maricopa	City Administration Maricopa, City Hall	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Marina	Layne Long, City Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Marina	Lisa Berkley, Councilmember	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Martinez	Eric Figueroa, City Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Martinez	Rob Schroder, Mayor	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Marysville	Marti Brown, City Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY
(CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
City	City of McFarland	Mario Gonzales, Public Works Director	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Mendota	Macario Banuelos, Public Works Superintendent	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Mendota	Mr. Cristian Gonzalez, City Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Mendota	Nancy Diaz, Finance Officer	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Menlo Park	City Administration Menlo Park, City Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Menlo Park	Harold Schapelhouman, Fire Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Menlo Park	Justin Murphy, City Manager,	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Merced	Stephanie Dietz, City Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Mill Valley	Alan Piombo, City Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
City	City of Mill Valley	Andrew Poster, Public Works Director	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Millbrae	Craig Centis, Superintendent of Public Works	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Milpitas	City Administration Milpitas, City Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Milpitas	Tony Ndah, Public Works Director	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Monte Sereno	City Administration Monte Sereno, City Clerk	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Monte Sereno	Jessica Kahn, City Engineer	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Monte Sereno	Terry Blount, City Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Monterey	Alan Haffa, Councilmember	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Monterey	Clyde Roberson, Mayor	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
City	City of Monterey	Dan Albert, Councilmember	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Monterey	Ed Smith, Councilmember	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Monterey	Hans Ulsar, City Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Monterey	Kristin Clark, Councilmember- Vice Mayor	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Monterey	Tyller Williamson, Councilmember	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Moraga	Cynthia Battenberg, Town Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Moraga	Mr. David Trotter, Mayor	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Morgan Hill	Anthony Eulo, Program Administrator	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Morgan Hill	Chris Ghione, Public Services Director	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
City	City of Morgan Hill	Christina Turner, City Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Mountain View	Dawn Cameron, Public Works Director	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Mountain View	Kimbra McCarthy, City Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Napa	Steve Potter, City Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Nevada City	Erin Minnett, Councilmember	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Nevada City	Joan Phillipe, City Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Newark	Art Interiano, Deputy Community Development Director	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Newark	City Administration Newark, General	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Newark	David J. Benoun, City Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
City	City of Newark	Kris Kokotaylo, Interim City Attorney	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Newark	Larry Kezar, Information Systems Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Newark	Laurie Gebhard, Assistant to the City Manager/Public Information Officer	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Newark	Lenka Hovorka, Assistant City Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Newark	Mr. Michael Holland, City Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Newark	Sheila Harrington, City Clerk	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Newark	Steven Turner, Community Development Director	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Newman	City Administration Newman, On-Call Public Works Employee	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Novato	Adam McGill, City Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
City	City of Oakdale	Bryan Whitemyer, City Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Oakdale	Jeff Gravel, Public Works Director	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Oakland	Ed Reiskin, Assistant City Administrator	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Oakland	Ed Reiskin, City Administrator	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Oakland	Ed Reiskin, City Administrator	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Oakland	Libby Schaaf, Mayor	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Oakley	Bryan Montgomery, City Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Oakley	Kevin Rohani, City Engineer	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Orange Cove	Rudy Hernandez, City Manager,	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY
(CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
City	City of Orinda	Steve Salomon, City Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Orland	Ed Vonasek, Public Works Director	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Orland	Peter Carr, City Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Oroville	Bill LaGrone, City Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Oroville	Chuck Reynolds, Mayor	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Oroville	Scott Thomson, Vice-Mayor	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Pacific Grove	Amy Tomlinson, Councilmember	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Pacific Grove	Ben Harvey, City Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Pacific Grove	Bill Peake, Mayor	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
City	City of Pacific Grove	Jenny McAdams, Councilmember	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Pacific Grove	Joe Amelio, Councilmember	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Pacific Grove	Nick Smith, Councilmember	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Pacifica	Kevin Woodhouse, City Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Paradise	Chris Rainey, General	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Paradise	Jody Jones, Councilmember	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Paradise	Karin Peppas, General	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Paradise	Kevin Phillips, Town Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Paradise	Rose Tryon, Councilmember	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
City	City of Paradise	Steve Crowder, Mayor	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Paradise	Steve Culleton, Supervisor	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Parlier	Alma Beltran, Mayor	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Petaluma	Brian Barnacle, Vice Mayor	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Petaluma	Dennis Pocekay, Councilmember	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Petaluma	Peggy Flynn, City Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Petaluma	Teresa Barrett, Mayor	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Piedmont	Daniel Gonzales, General	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Piedmont	Echa Schneider, Communications Program Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY
(CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
City	City of Piedmont	John Tulloch, Assistant City Administrator	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Piedmont	Nick Milosovich, Public Works Supervisor	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Piedmont	Sara Lillevand, General	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Pinole	Andrew Murray, City Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Pittsburg	Garrett Evans, City Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Placerville	Cleve Morris, City Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Placerville	Dave Warren, Assistant City Manager/Director of Finance	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Placerville	Kara Taylor, Mayor	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Placerville	Michael Saragosa, Vice Mayor	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
City	City of Placerville	Terry Zeller, Director Of Community Services	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Pleasant Hill	June Catalano, City Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Pleasanton	Allen Hammond, Director of Information Technologies	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Pleasanton	Becky Hopkins, Assistant to the City Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Pleasanton	Brian Dolan, City Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Pleasanton	Cindy Chin, Public Information Officer	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Pleasanton	Heidi Murphy, Director of Library and Recreation	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Pleasanton	Jerry Thorne, Mayor	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Pleasanton	Kathleen Yurchak, Director of Operations and Water Utilities	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
City	City of Pleasanton	Leo Lopez, Emergency Services Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Pleasanton	Mike Tassano, City Traffic Engineer	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Pleasanton	Nelson Fialho, City Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Pleasanton	Pamela Ott, Director of Economic Development	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Pleasanton	Steve Kirkpatrick, Director of Engineering	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Pleasanton	Tracey Hein, Emergency Preparedness Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Plymouth	Rex Osborn, City Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Point Arena	Amy Herman, Deputy City Clerk	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Point Arena	Paul Andersen, City Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY
(CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
City	City of Portola Valley	Howard Young, Public Works Director	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Portola Valley	Jeremy Dennis, Town Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Red Bluff	Richard Crabtree, City Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Redwood City	Melissa Diaz, City Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Reedley	Ms. Nicole Zieba, City Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Richmond	Henry Gardner, City Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Richmond	Tom Butt, Mayor	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Rio Dell	Kyle Knopp, City Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Ripon	Kevin Werner, City Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
City	City of Riverbank	Michael Riddell, Public Works Director	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Riverbank	Sean Scully, City Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Rohnert Park	Aaron Johnson, Deputy Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Rohnert Park	Darrin Jenkins, City Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Rohnert Park	Don Schwartz, Asst City Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Rohnert Park	Gerard Giudice, Mayor	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Rohnert Park	Gina Belforte, Councilmember	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Rohnert Park	Jackie Elward, Vice Mayor	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Rohnert Park	Mike Bates, Deputy Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
City	City of Rohnert Park	Tim Mattos, Director of Public Safety	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Rohnert Park	Willy Linares, Councilmember	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Ross	Joe Chinn, Town Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Ross	Linda Lopez, Town Clerk	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Saint Helena	Mark Prestwich, City Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Salinas	Christie Cromeenes, Councilmember	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Salinas	Steve Carrigan, City Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Salinas	Steve McShane, Councilmember	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Salinas	Tony Barrera, Councilmember	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
City	City of San Anselmo	David P. Donery, Town Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of San Bruno	City Administration San Bruno, City Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of San Carlos	Jeff Maltbie, City Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of San Carlos	Louis Duran, Public Works Superintendent	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of San Carlos	Nicole MacDonald, Senior Management Analyst	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of San Carlos	Steven Machida, Public Works Director	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of San Carlos	Tara Peterson, Assistant City Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of San Francisco	Naomi Kelly, General	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of San Joaquin	Elizabeth Nunez, City Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
City	City of San Jose	Carolina Camarena, Communications Officer	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of San Jose	David Sykes, City Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of San Jose	Jim Ortbal, Deputy City Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of San Jose	Kip Harkness, Deputy City Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of San Jose	Lee Wilcox, Chief of Staff	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of San Jose	Sam Liccardo, Mayor	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of San Juan Bautista	Don Reynolds, City Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of San Juan Bautista	John Freeman, Councilmember	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of San Juan Bautista	Leslie Jordan, Mayor	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY
(CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
City	City of San Juan Bautista	Mary Edge, Councilmember	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of San Juan Bautista	Shawn Freels, Councilmember	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of San Leandro	City Administration San Leandro, City Hall	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of San Luis Obispo	Wade Horton, County Administrator	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of San Mateo	Christina Horrisberger, Deputy Director	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of San Mateo	Drew Corbett, City Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of San Mateo	Kathy Kleinbaum, Assistant City Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of San Mateo	Kohar Kojayan, Director	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of San Mateo	Mike Titsworth, Building Official	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY
(CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
City	City of San Pablo	City Administration San Pablo, Assistant City Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of San Pablo	Matt Rodriquez, City Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of San Pablo	Rich Kinney, Mayor	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of San Rafael	Jim Schutz, City Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of San Rafael	Patrick Bignardi, Vegetation management Inspector Fire Prevention	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of San Ramon	Bill Clarkson, Mayor	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of San Ramon	Clifford Buxton, Emergency Preparedness	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of San Ramon	Eric Ramos, Engineering Specialist	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of San Ramon	Joe Gorton, City Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY
(CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
City	City of San Ramon	Maria Fierner, Public Works Director	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of San Ramon	Paige Meyer, Fire Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Sand City	Aaron Blair, City Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Sand City	Gregory Hawthorne, Councilmember	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Sand City	Jerry Blackwelder, Mayor Pro Tem,	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Sand City	Kim Cruz, Councilmember	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Sand City	Libby Sofer, Councilmember	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Sand City	Linda Scholink, City Clerk	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Sand City	Mrs. Mary Ann Carbone, Mayor	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
City	City of Sanger	Silver Rodriguez, Police Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Sanger	Tim Chapa, City Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Santa Cruz	Donna Meyers, Councilmember	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Santa Cruz	Jim Ross, Lieutenant	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Santa Cruz	Justin Cummings, Councilmember	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Santa Cruz	Martine Watkins, Councilmember	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Santa Cruz	Mr. Martin Bernal, City Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Santa Cruz	Renee Golder, Councilmember	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Santa Cruz	Shebreh Kalantari-Johnson, Councilmember	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
City	City of Santa Cruz	Sonja Bruner, Councilmember	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Santa Cruz	Sonja Brunner, Mayor Pro Tem,	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Santa Maria	Marc Schneider, Police Department	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Santa Maria	Roy Dugger, Emergency Services Specialist	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Santa Maria	Todd Tuggle, Interim Fire Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Santa Rosa	Adriane Mertens, Public Information Officer	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Santa Rosa	Dan Marincik, Lieutenant	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Santa Rosa	David Guhin, Planning and Economic Development Director	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Santa Rosa	David Thomas, Admin Sergeant	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY
(CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
City	City of Santa Rosa	Neil Bregman, Emergency Preparedness Coordinator	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Santa Rosa	Scott Westrope, Deputy Fire Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Santa Rosa	Sean McGlynn, City Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Santa Rosa	Steve Suter, Battalion Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Saratoga	Crystal Bothelio, Deputy City Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Saratoga	James Lindsey, City Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Saratoga	Lauren Pettipiece, Public Information Officer	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Sausalito	Marcia Raines, City Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Scotts Valley	Daryl Jordan, Public Works Director	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
City	City of Scotts Valley	Derek Timm, Councilmember	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Scotts Valley	Donna Lind, Mayor	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Scotts Valley	Jack Dilles, Councilmember	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Scotts Valley	Jim Reed, Mayor Pro Tem	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Scotts Valley	ScRandy Johnson, Mayor	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Scotts Valley	Tina Friend, City Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Seaside	Craig Malin, City Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Seaside	Dave Pacheco, Councilmember	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Seaside	Ian Oglesby, Mayor	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
City	City of Seaside	Jason Campbell, Councilmember	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Seaside	Jon Wizard, Councilmember	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Sebastopol	Larry McLaughlin, City Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Sebastopol	Mary Gourley, Assistant City Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Selma	Ms. Teresa Gallavan, City Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Shafter	City Administration Shafter, City Hall	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Soledad	Alejandro Chavez, Mayor Pro Tem.	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Soledad	Anna Velazquez, Mayor	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Soledad	Brent Slama, Acting City Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
City	City of Soledad	Carla Strobridge Stewart, Councilmember	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Soledad	Marisela Lara, Councilmember	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Soledad	Oscar Antillon, Public Works Director	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Sonoma	Amy Harrington, Councilmember	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Sonoma	Coleen Fergusen, Public Works Director/City Engineer	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Sonoma	David Kiff, Interim City Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Sonoma	Sue Casey, Assistant City Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Sonora	Mary Rose Rutikanga, City Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of South San Francisco	Leslie Arroyo, Communications Director	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
City	City of South San Francisco	Mike Futrell, City Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Stockton	Connie Cochran, Community Relations Officer	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Suisun	Gemma Geluz, General	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Suisun	Greg Folsom, City Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Sunnyvale	Chip Taylor, Public Works Director	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Sunnyvale	Kent Steffens, City Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Sutter Creek	Amy Gedney, City Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Sutter Creek	Linda Rianda, City Council	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Taft	City Administration Taft, City Hall	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
City	City of Tehama	Robert Mitchell, Mayor	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Tiburon	Greg Chanis, Town Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Tiburon	Jaime Scardina, Police Chief/MCSO	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Tiburon	Richard Pearce, Fire Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Tracy	Jenny Haruyama, City Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Trinidad	Daniel Berman, City Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Ukiah	Mel Grandi, City Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Union City	Carol Dutra-Vernaci, Mayor	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Union City	Joan Malloy, City Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
City	City of Union City	Richard Martinez, Emergency Services Coordinator	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Vacaville	Aaron Busch, City Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Vacaville	Dawn Leonardini, Assistant City Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Vallejo	Greg Nyhoff, City Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Vallejo	Pippin Dew, Councilmember	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Vallejo	Robert McConnell, Mayor	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Vallejo	Rozzana Verder, Vice-Mayor	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Vallejo	Veronica Nebb, City Attorney	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Walnut Creek	Betsy Burkhart, Communications Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
City	City of Walnut Creek	Carla Hansen, Deputy City Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Walnut Creek	Dan Buckshi, City Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Walnut Creek	Loella Haskew, Councilmember	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Walnut Creek	Teri Killgore, Assistant City Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Wasco	City Administration Wasco, City Hall	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Watsonville	Ari Parker, Councilmember	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Watsonville	Aurelio Gonzalez, Councilmember	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Watsonville	Eduardo Montesino, Councilmember	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Watsonville	Felipe Hernandez, Councilmember	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
City	City of Watsonville	Francisco Estrada, Councilmember	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Watsonville	Jimmy Dutra, Mayor	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Watsonville	Lowell Hurst, Councilmember	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Watsonville	Matt Huffaker, City Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Watsonville	Rebecca Garcia, Mayor	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Watsonville	Trina Coffman, Councilmember	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of West Sacramento	City Administration West Sacramento, General	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Wheatland	Jim Goodwin, City Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Willits	Brian Bender, City Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY
(CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
City	City of Willits	Cathy Moorhead, Deputy City Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Willits	James Robbins, Assistant PIO	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Willits	Kenan OShea, Public Works Superintendent	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Willits	Scott Herman, Utilities Superintendent	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Willits	Tamara Alaniz, Brooktrail Town Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Willits	Wayne Peabody, City Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Windsor	Dominic Foppoli, Mayor	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Windsor	Ken MacNab, Town Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Winters	City Administration Winters, General	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
City	City of Winters	Mr. John W. Donlevy Jr., City Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Woodland	City Administration Woodland, General	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Woodside	Kevin Bryant, Town Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Yountville	Joe Tagliaboschi, Public Works Director	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Yountville	Mr. Steve Rogers, City Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Yountville	Samantha Holland, Parks and Rec Director	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City	City of Yuba City	Diana Langley, City Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Bear Valley Fire Department	Bear Valley Fire Department Alpine County, General	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Burney Fire	Mr. Monte Keady, Fire Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
City Emergency Services	City of Albany	Nicole Almaguer, City Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Area Coordinator	Josh Chadwick, Fire Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	Aaron Lacey, Deputy Fire Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	Alec Tune, General	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	Amy New, Fire Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	Andrew Lee, Deputy Fire Marshal	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	Ari Delay, Fire Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	Art Paquette, Fire Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	Ava Fanucchi, Deputy Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
City Emergency Services	Fire Department	Barry Biermann, Deputy Fire Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	Bill Braga, Fire Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	Bob Martin Del Campo, Fire Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	Bobby Brand, Battalion Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	Brian Dempsey, General	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	Brian Loventhal, City Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	Brittany Miller, Deputy Emergency Preparedness Coordinator	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	Bryan Craig, Fire Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	Bryan Jonson, Fire Marshal	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY
(CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
City Emergency Services	Fire Department	Cheryl Goetz, Fire Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	Chris Tenns, Division Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	Chris Wynkoop, Fire Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	Chris Zinko, General	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	Christopher Dorn, Fire Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	City of Placerville Fire Department, Station 19	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	Curtis Jacobson, Fire Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	Dale Fishback, Fire Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	Dan Grebil, Fire Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY
(CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
City Emergency Services	Fire Department	Daniel Perkins, General	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	Darin White, Fire Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	Dave Brannigan, Fire Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	Dave Brannigan, General	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	Dave Jordan, Fire Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	Dave Pucci, Acting Fire Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	Dave Pucci, Non-Emergency	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	Dave Winnacker, Fire Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	David Bramell, Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
City Emergency Services	Fire Department	David Brannigan, Fire Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	Debbie Mackey, Fire Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	Derek Parker, Fire Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	Dominic Moreno, Fire Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	Don Bullard, Fire Marshal	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	Doug McCoun, Fire Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	Dr. Jason Boaz, Fire Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	Dwayne Gabriel, Fire Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	Dwight Good, Unit Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
City Emergency Services	Fire Department	Eric Zane, Fire Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	Erik Brotemarkle, Emergency	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	Fire Department Arcata, General, N/A	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	Fire Department Arvin, Arvin Fire, N/A	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	Fire Department Atwater, Emergency	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	Fire Department Atwater, General	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	Fire Department Belvedere, General	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	Fire Department Burlingame, Emergency	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	Fire Department Capitola, Fire Prevention	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY
(CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
City Emergency Services	Fire Department	Fire Department Carmel-by-the-sea, General	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	Fire Department Clovis, Emergency	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	Fire Department Clovis, General	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	Fire Department Coalinga, Emergency	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	Fire Department Colma, Emergency	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	Fire Department Colma, Non-Emergency	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	Fire Department Concord, Emergency	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	Fire Department Davis, Emergency	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	Fire Department Davis, Non-Emergency	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
City Emergency Services	Fire Department	Fire Department Dixon, General	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	Fire Department Dublin, General	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	Fire Department East Palo Alto, Non-Emergency	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	Fire Department El Cerrito, General	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	Fire Department Escalon, Business	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	Fire Department Fairfield, General	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	Fire Department Fortuna, General	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	Fire Department Hillsborough, Emergency	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	Fire Department Hillsborough, Non-Emergency	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
City Emergency Services	Fire Department	Fire Department Hollister, Station 1	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	Fire Department Kingsburg, Emergency	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	Fire Department Livingston, Station 96	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	Fire Department Los Altos, Emergency	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	Fire Department Los Altos, Non-Emergency	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	Fire Department Maricopa, Station 22	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	Fire Department McFarland, Station 33	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	Fire Department Milpitas, Emergency	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	Fire Department Milpitas, Non-Emergency	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY
(CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
City Emergency Services	Fire Department	Fire Department Morro Bay, General (24-hour)	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	Fire Department Mountain View, Non-Emergency	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	Fire Department Newark, Fire Prevention	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	Fire Department Newman, On Call Officer	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	Fire Department OES Duty Officer, General	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	Fire Department Petaluma, Emergency	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	Fire Department Portola Valley, Emergency	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	Fire Department Rio Dell, General	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	Fire Department Rio Vista, Dispatch	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
City Emergency Services	Fire Department	Fire Department Rio Vista, Non-Emergency	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	Fire Department Ross, General	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	Fire Department San Anselmo, General	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	Fire Department San Pablo, General	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	Fire Department Sand City, General	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	Fire Department Sanger, Emergency	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	Fire Department Santa Maria, General (24-hour)	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	Fire Department Scotts Valley, General	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	Fire Department Shafter, Station 32	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY
(CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
City Emergency Services	Fire Department	Fire Department Solvang, Station 30	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	Fire Department Suisun City, General	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	Fire Department Taft, Station 21	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	Fire Department Tiburon, General	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	Fire Department Trinidad, General	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	Fire Department Vacaville, General	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	Fire Department Vallejo, General	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	Fire Department Wasco, Station 31	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	Fire Department West Sacramento, Non-Emergency	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
City Emergency Services	Fire Department	Fire Department Willows, Non-Emergency	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	Fire Department Winters, Non-Emergency	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	Fire Department Woodland, General	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	Fire Department Woodland, Non-Emergency	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	Fire Department Yuba City, General	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	Fred Gaumnitz, Fire Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	Garrett Contreras, Fire Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	Gaudenz Panholzer, Fire Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	Gene Neely, Fire Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
City Emergency Services	Fire Department	Greg Da Cunha, Deputy Fire Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	Jake Hess, Fire Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	Jake Hess, Fire Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	Janine Nicholson, Fire Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	Jason Alexander, Fire Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	Jason Hajduk, Fire Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	Jason Jenkins, Fire Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	Jason Muscio, Fire Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	Jeff Gilbert, Fire Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
City Emergency Services	Fire Department	Jeff Peters, Fire Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	Jeff Schach, Assistant Fire Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	Jerry Isaak, Fire Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	Jim Langborg, Fire Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	Jimmy Cherry, Deputy Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	Joe Testa, Fire Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	John Borboa, Fire Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	John Frando, Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	John Rohrabaugh, Fire Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
City Emergency Services	Fire Department	John Serritelli, Fire Department Admin. Assist.	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	John Sorensen, Fire Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	Jonathan Stornetta, Fire Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	Jordan Webster, Non-Emergency	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	Justin Chaney, Fire Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	Keith Aggson, Fire Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	Keith Bowen, Fire Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	Keith May, Assistant Fire Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	Ken Anderson Sr., Non-Emergency	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
City Emergency Services	Fire Department	Kevin Albertson, Deputy Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	Kirk Thomson, Fire Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	Kyle Heggstrom, Fire Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	Lance MacDonald, General	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	Len Thompson, Fire Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	Lon Winburn, Fire Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	Manuel Lopez, Fire Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	Mark Buttron, Fire Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	Mark Hartwig, Fire Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
City Emergency Services	Fire Department	Mark Heine, Fire Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	Mason Hurley, Fire Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	Matt Gallagher, Fire Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	Matt Harris, Fire Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	Matt Watson, Duty Chief, Designated POC	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	Melinda Drayton, Fire Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	Michael Pigoni, Fire Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	Mike Alforque, Deputy Fire Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	Mike Van Loben Sels, Fire Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
City Emergency Services	Fire Department	Mitch Franklin, Fire Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	Mitch Higgins, Fire Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	Mr. Anthony Velasquez, Fire Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	Mr. Bill Tyler, Fire Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	Mr. Greg Tarascou, Fire Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	Mr. John Binaski, Fire Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	Mr. Jon Noyer, Brooktrails Fire Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	Nathan Pry, Emergency Coordinator	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	Paige Meyer, Fire Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
City Emergency Services	Fire Department	Paul Horvat, Emergency Services Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	Paul Lowenthal, Assistant Fire Marshal	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	Pittsburg Fire Department, Non-Emergency	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	Police Department Clayton, Fire Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	Ray Stonebarger, Fire Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	Rob Lindner, Fire Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	Rob Lindner, Fire Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	Robby Cassou, Fire Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	Robert Hall, Fire Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
City Emergency Services	Fire Department	Robert Marshall, Fire Marshal	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	Robert Petersen, Fire Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	Robert Sapien, Fire Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	Roger Steinhoff, Fire Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	Ron Karlen, Fire Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	Ron Whittle, Fire Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	Rudy Lopez, Fire Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	Russ Nichols, Fire Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	Ryan Mack, Fire Captain	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
City Emergency Services	Fire Department	Sam Goodspeed, Division Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	Sean Robertson, Fire Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	Steve Akre, Fire Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	Steve Binns, Fire Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	Steve Butler, Fire Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	Steve Lieberman, Fire Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	Steve Orsi, Fire Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	Steve Standridge, Fire Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	Tenney Joe, Fire Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
City Emergency Services	Fire Department	Tim Henry, General	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	Tom Greenwood, General	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	Tom Welch, Fire Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	Tony Madrigal, General	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	Walling Emily, Fire Marshal	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	Zach Curren, Fire Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	Zoraida Diaz, General	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Office of Education	Nelson Alegria, Safety & Emergency Preparedness Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Orland Fire Department	Fire Department Glenn County, General	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
City Emergency Services	Police Department	Adele Frese, Police Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Albert Pardini, Police Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Alex Gammelgard, Police Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Allan Shields, Police Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Allwyn Brown, Police Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Andrew Dally, Police Captain	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Andrew Mills, Police Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Andrew White, Chief of Police	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Angela Averiett, Chief of Police	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
City Emergency Services	Police Department	Anthony Borgman, Lieutenant	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Ben Alldritt, Police Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Bill Frass, Police Captain	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Bill Scott, Police Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Billy Aldridge, Police Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Brent Kidder, Police Sergeant	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Brian Amoroso, Police Captain	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Brian Bubar, Police Captain	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Brian Ferrante, Police Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
City Emergency Services	Police Department	Cameron Christensen, Police Captain	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Cameron Kovacs, Lieutenant	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Chad Ellis, Police Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Chomnan Loth, Police Captain	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Chris Bourquin, Police Commander	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Chris Monahan, Police Captain	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Chris Parker, Lieutenant	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Chris Soria, Police Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Christopher Mynderup, Police Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
City Emergency Services	Police Department	Cucchi Anthony, Deputy Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Curt Fleming, Police Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Dale Stoebe, Police Lieutenant	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Damon Wasson, Police Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Dan Mulholland, Police Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Dan Wiegers, Police Lieutenant	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Darren Pytel, Chief of Police	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Dave Hober, Police Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	David Cook, Police Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
City Emergency Services	Police Department	David Higbee, Police Lieutenant	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	David Honda, Police Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	David Riviere, Police Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	David Swing, Police Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	David Tindall, Acting Police Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Deanna Cantrell, Police Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Deanna Cantrell, Police Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Denton Carlson, Captain	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Devon Popovich, Emergency	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
City Emergency Services	Police Department	Diana Burnett, Emergency	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Diane Hendry, Division Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Dino Lawson, Police Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Ed Barberini, Police Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Ed Ormonde, Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Elise Warren, Police Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Erik Reinbold, Police Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Erik Upson, City Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Erin Kiely, Police Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
City Emergency Services	Police Department	Fabian Lizarraga, Police Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Fred Dauer, Lieutenant	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Gary Redman, Police Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	George Turegano, Fire Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Gina Anderson, Police Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Greg Allen, Police Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Greg Keeney, Captain	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Gregg Andreotti, Emergency	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Guy Swanger, Police Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
City Emergency Services	Police Department	Jada Chiu, Community Engagement Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Jake Miller, Police Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	James Conner, Police Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	James Hunt, Police Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	James O'Connell, Police Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Jamie Field, Chief of Police	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Janet Davis, Emergency	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Jared Rinetti, Police Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Jason Ferguson, Police Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
City Emergency Services	Police Department	Jason Wu, Police Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Jeff Arnold, Police Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Jeff Bell, Emergency	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Jeff Hoyne, Police Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Jeff Jennings, Chief of Police	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Jeff Snith, Police Captain	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Jeff Tudor, Non-Emergency	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Jennifer Louis, Interim Police Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Jennifer Ponce, Emergency Services Coordinato	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
City Emergency Services	Police Department	Jeramie Struthers, Captain	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Jeremy Bowers, Police Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Jeremy Young, Police Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Jody Cox, Police Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Jody Estarziau, Police Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Joe Gomez, Police Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Joe Vlach, Police Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	John Gamez, Police Captain	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	John Golden, Emergency	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
City Emergency Services	Police Department	John Miller, Police Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	John Peters, Police Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	John Rohrbacher, Police Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Jolie Macias, Police Lieutenant	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Jon King, Police Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Jonathan Arguello, Police Captain	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Jose Garza, Dispatch	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Jose Garza, Dispatch	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Joshua Stephens, Emergency	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
City Emergency Services	Police Department	Katie Krauss, Captain	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Keith Boyd (Monterey), Chief of Police	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Keith Wise, Police Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Kelsey Carreiro, Emergency Services Coordinator	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Ken Savano, Police Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Kevin Zimmermann, Emergency	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	LaRonne Armstrong, Police Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Lisa Douglas, Support Services Commander	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Lisa Macias, Police Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
City Emergency Services	Police Department	Manjit Sappal, Chief of Police	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Mario Garcia, Police Commander	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Mark Koller, Police Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Marty Rivera, Interim Police Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Matt Jenkins, Police Lieutenant	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Matt McCaffrey, Police Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Matthew Breen, Communications Supervisor	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Matthew Snelson, General	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Michael Cash, Police Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
City Emergency Services	Police Department	Michael Kendall, Police Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Michael Norton, Police Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Michael Norton, Police Chie	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Michael Salvador, Emergency	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Michele Clubb, Communications Supervisor	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Miguel Contreras, Sergeant	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Mike Matteucci, Police Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Milt Medeiros, Emergency	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Mitchell Celaya, Police Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
City Emergency Services	Police Department	Mr. Brad Rasmussen, Police Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Mr. Gary Brizzee, Police Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Neil Dadian, Emergency	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	NicLuis Rodriguez, General	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Orlando Rodriguez, Police Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Paco Balderrama, Police Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Parker Sever, Dispatch	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Patrick Hensley, Police Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Paul Keith, Police Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
City Emergency Services	Police Department	Paul Kunkel, Non-Emergency	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Paul Tomasi, Police Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	PD-Dispatch Atherton, Dispatch	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Pecoraro Victor, Police Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Pittsburg Police Department, Emergency	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Police Department Albany, Emergency	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Police Department American Canyon, Dispatch	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Police Department Antioch, Emergency	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Police Department Bakersfield, General	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
City Emergency Services	Police Department	Police Department Brentwood, General	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Police Department Campbell, Emergency	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Police Department Capitola, Non-Emergency	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Police Department Carmel-by-the-Sea, General	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Police Department Clearlake, Non-Emergency	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Police Department Colma	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Police Department Colma, Police Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Police Department Colusa, General	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Police Department Cotati, Emergency	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
City Emergency Services	Police Department	Police Department Davis, Emergency	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Police Department Dinuba, Tip Line	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Police Department Dispatch, General	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Police Department Dixon, Non-Emergency	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Police Department Dublin, Non-Emergency	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Police Department East Palo Alto, Emergency	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Police Department Escalon, Emergency	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Police Department Escalon, Non-Emergency	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Police Department Fairfield, Emergency	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
City Emergency Services	Police Department	Police Department Fowler, Emergency	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Police Department Fowler, General	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Police Department Fresno, Emergency	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Police Department General, Police Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Police Department Gridley, General	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Police Department Guadalupe, Dispatch	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Police Department Hollister, Non-Emergency	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Police Department King City, Dispatch	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Police Department Larkspur, Dispatch	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
City Emergency Services	Police Department	Police Department Lathrop, Non-Emergency	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Police Department Lincoln, Emergency	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Police Department Los Altos, Emergency	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Police Department Los Altos, Non-Emergency	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Police Department Madera, Emergency	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Police Department Marina, Non-Emergency	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Police Department Menlo Park, Emergency	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Police Department Menlo Park, Non-Emergency	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Police Department Millbrae, Emergency	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
City Emergency Services	Police Department	Police Department Milpitas, Non-Emergency	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Police Department Monte Sereno, Police Captain	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Police Department Monterey, Emergency	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Police Department Morgan Hill, Non-Emergency	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Police Department Mountain View, Non-Emergency	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Police Department Napa, Non-Emergency	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Police Department Newark, Police Emergency Dispatch	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Police Department Pacific Grove, Non-Emergency	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Police Department Pacifica, Non-Emergency	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
City Emergency Services	Police Department	Police Department Pinole, General	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Police Department Pittsburg, Non-Emergency	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Police Department Pleasant Hill, Emergency	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Police Department Pleasanton, Non-Emergency	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Police Department Rio Dell, Dispatch	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Police Department Rio Vista, Non-Emergency	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Police Department Rohnert Park, General	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Police Department Salinas, Non-Emergency	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Police Department San Bruno, Emergency	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
City Emergency Services	Police Department	Police Department San Luis Obispo, Non-Emergency	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Police Department Sanger, Emergency	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Police Department Santa Cruz, Non-Emergency	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Police Department Santa Maria, Dispatch	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Police Department Seaside, Non-Emergency	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Police Department Selma, Emergency	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Police Department Soledad, Non-Emergency	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Police Department Suisun City, Emergency	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Police Department Suisun City, Non-Emergency	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
City Emergency Services	Police Department	Police Department Tiburon, Dispatch	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Police Department Vacaville, Emergency	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Police Department Vallejo, Non-Emergency	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Police Department Watch Commander, Police Watch Commander	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Police Department West Sacramento, Non-Emergency	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Police Department Wheatland, Dispatch	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Police Department Williams, General	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Police Department Winters, Non-Emergency	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Police Department Yuba City, Non-Emergency	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
City Emergency Services	Police Department	Police Taft, Taft Police Department	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Raffaello Pata, Police Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Rainer Navarro, Police Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Randy Richardson, Non-Emergency	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Reuben Shortnacy, Dispatch	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Rich Urena, Emergency	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Richard McEachin, Police Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Rick Navarro, Police Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Rico Tabaranza, Police Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
City Emergency Services	Police Department	Robyn Pope-Burgess, Police Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Ron Raman, Chief of Police	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Ruben Martinez, Police Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Rudy Alcaraz, Police Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Russell Stivers, Emergency	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Salvador Raygoza, Police Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Scott Campbell, Police Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Scott Heller, Police Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Sean Washington, Police Captain	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
City Emergency Services	Police Department	Shane Palsgrove, Police Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Sheriff's Office Half Moon Bay, Non-Emergency	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Sheriff's Office San Carlos, Sheriff's Office	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Steve Walpole, Police Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Steve Watson, Police Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Sylvia Moir, Police Chief (Interim)	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Terry McManus, Police Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Todd Fordahl, Police Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Tom Cavallero, Police Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
City Emergency Services	Police Department	Tom Chaplin, Police Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Tom Hansen, Police Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Toni-Lynn Charlop, Emergency	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Tony Psaila, Police Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Travis DiGuilio, General	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Turu VanderWiel, Police Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	Ty Lewis, City Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Police Department	William Goswick, Police Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	West Point Fire District	Bill Fullerton, Fire Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
City Emergency Services	West Stanislaus Fire District	Michael Whorton, Fire Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	Brian Dempsey, General	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	Casey Bryson, Fire Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	Dave Marques, Emergency Coordinator	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	Dennis Bitters, Fire Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	Fire Department Colfax, General	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	Fire Department Paso Robles, Non-Emergency	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	Fire Department Pismo Beach, General (24-hour)	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	Fire Department Salinas, Non-Emergency	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
City Emergency Services	Fire Department	Fire Department San Juan Bautista, General	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	Fire Department Soledad, General	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	Jim Comisky, Assistant Fire Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	Kyle Shipherd, Fire Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	Mike Cahill, Fire Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	Pablo Barreto, Fire Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	Shannon Lewis, Emergency Coordinator	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	Stephen Lieberman, Fire Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
City Emergency Services	Fire Department	Steve Campbell, Fire Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
City Emergency Services	Fire Department	Steve Knuckles, Fire Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County	Alameda County	County Administration Alameda County, President of the Board	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County	Alameda County	Ms. Susan Muranishi, County Administrator	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County	Alpine County	Nichole Williamson, County Administrative Officer	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County	Alpine County	Terry Woodrow, County Supervisor	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County	Amador County	Chuck Iley, County Administrator	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County	Amador County	Frank Axe, Supervisor	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County	Butte County	Andy Pickett, CAO	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County	Butte County	Brian Ring, General	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
County	Butte County	Casey Hatcher, General	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County	Butte County	Danette York, Public Health Director	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County	Butte County	Danielle Nuzum, General	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County	Butte County	Debbie Heath, General	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County	Butte County	Grant Hunsicker, General Services Director	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County	Butte County	Joshua Pack, Director	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County	Butte County	Lisa Almaguer, General	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County	Butte County	Meegan Jessee, General	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County	Butte County	Pete Calarco, General	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
County	Butte County	Racheal Maxwell, General	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County	Calaveras County	Albert Alt, Supervisor	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County	Calaveras County	Ben Stopper, Supervisor	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County	Calaveras County	Chris Edgerly, Health Officer	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County	Calaveras County	Jack Garamendi, Supervisor	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County	El Dorado County	Don Ashton, CAO	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County	El Dorado County	George Turnboo, Chair of the Board	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County	El Dorado County	John Hidahl, Chair of the Board	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County	El Dorado County	Kristine Guth, Health and Human Services	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
County	Fresno County	Jean Rousseau, County Executive Officer	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County	Fresno County	Nathan Magsig, Chair of the Board	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County	Glenn County	Don Rust, Planning Director	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County	Glenn County	Scott DeMoss, CAO	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County	Kings County	Edward Hill, CAO	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County	Kings County	Roger Bradley, Asst. County Administrator	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County	Lake County	Bruno Sabatier, Chair of the Board	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County	Lake County	Scott Harter, Special Districts Administrator	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County	Lake County	Susan Parker, County Administrative Officer	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
County	Lassen County	Richard Egan, CAO	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County	Lassen County	Tony Shaw, Deputy Chief Administrative Officer	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County	Madera County	Jay Varney, CAO	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County	Madera County	Robert Poythress, Board of Supervisors- Dist. 3	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County	Madera County	Tom Wheeler, Councilmember	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County	Marin County	Ethan Simpson, General	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County	Marin County	Matthew Hymel, CAO	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County	Marin County	Tucker Evans, General	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County	Mariposa County	County Administration Mariposa County, Councilmember	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
County	Mariposa County	Marshall Long, County Supervisor,	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County	Mariposa County	Steven Ward, Division Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County	Mendocino County	Ms. Carmel Angelo, County Executive Officer	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County	Merced County	Daron McDaniel, Supervisor	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County	Merced County	James Brown, County Executive Officer	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County	Monterey County	Brandon Gates, Public Health Program Manager, Health	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County	Monterey County	Charles McKee, CAO	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County	Monterey County	Chris Lopez, Supervisor -- District 3	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County	Monterey County	Don Clark, General	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
County	Monterey County	Edward Moreno, Bureau Chief, Health	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County	Monterey County	John Greathouse, Chronic Disease Prevention Coordinator, Health	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County	Monterey County	John M. Phillips - District, Supervisor	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County	Monterey County	Kristy Michie, Assistant Bureau Chief, Health	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County	Monterey County	Luis Alejo, Supervisor	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County	Monterey County	Mary Adams (District 5), Board Chair	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County	Monterey County	Nicholis Steller, Health Program Coordinator, Health	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County	Monterey County	Steven Fischer, Superior Court of California	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County	Monterey County	Wendy Askew, Supervisor - District 4	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
County	Napa County	Minh Tran, County Executive Officer	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County	Placer County	Todd Leopold, CEO	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County	Plumas County	Gabriel Hydrick, CAO	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County	San Benito County	Bea Gonzales, Board Chair	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County	San Benito County	Bob Tiffany, Supervisor	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County	San Benito County	Kollin Kosmicki, Supervisor	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County	San Benito County	Ray Espinosa, CAO	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County	San Joaquin County	Tom Patti, Supervisor	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County	San Luis Obispo County	Guy Savage, Assistant County Administrator	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
County	Santa Barbara County	Mona Miyasato, County Executive Officer	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County	Santa Barbara County	SBCO General Services Facilities-South County, Energy Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County	Santa Barbara County	Scott Hosking, Facilities Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County	Santa Clara County	Communications 9-1-1 Dispatch Santa Clara County, Watch Commander,	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County	Santa Clara County	County Administration Santa Clara County, Chief Operating Officer	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County	Santa Clara County	Garry Herceg, Deputy CEO	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County	Santa Clara County	Jeffrey Smith, County Executive Officer	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County	Santa Clara County	Joe Simitian, County Supervisor	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County	Santa Clara County	Michael Cabano, Emergency	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
County	Santa Clara County	Public Health Department Santa Clara County, Public Health Officer	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County	Santa Cruz County	Bruce McPherson, Supervisor	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County	Santa Cruz County	Carlos Palacios, CAO	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County	Santa Cruz County	David Reid, General	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County	Santa Cruz County	Dispatch Santa Cruz County, Non-Emergency	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County	Santa Cruz County	Greg Caput, Supervisor	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County	Santa Cruz County	Jason Hoppin, Communications Director	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County	Santa Cruz County	Manu Koenig, Supervisor	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County	Santa Cruz County	Nicole Coburn, Assistant CAO	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
County	Santa Cruz County	Ryan Coonerty, Supervisor - Board Chair	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County	Santa Cruz County	Zach Friend, Supervisor	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County	Shasta County	Matt Pontes, CEO	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County	Sierra County	Jim Beard, Chair, Supervisor District 4	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County	Sierra County	Lee Adams, Supervisor	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County	Sierra County	Peter Huebner, Supervisor District	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County	Siskiyou County	Angela Davis, CAO	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County	Solano County	Birgitta Corsello, County Administrator	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County	Solano County	Erin Hannigan, Supervisor	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY
(CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
County	Sonoma County	Jennifer Larocque, Communications & Engagement Coordinator	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County	Sonoma County	Lynda Hopkins, County Supervisor, District 5	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County	Sonoma County	Mellisa Valle, Communications & Engagement Coordinator	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County	Sonoma County	Sheryl Bratton, CAO	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County	Tehama County	Bill Goodwin, CAO	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County	Tehama County	Brant Mesker, Administrative Analyst	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County	Trinity County	Richard Kuhns, CAO	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County	Tulare County	County Administration Tulare County, County Administrator	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County	Tuolumne County	County Administration Tuolumne County, Emergency Coordinator	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
County	Tuolumne County	Jim Garaventa, Mayor	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County	Tuolumne County	Matt Hawkins, Councilmember	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County	Tuolumne County	Security Operations Tuolumne County, General	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County	Yuba County	Andy Vasquez, Supervisor District	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County	Yuba County	Homer Rice, Health Administrator	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County	Yuba County	Jennifer Vasquez, Director	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County	Yuba County	Kevin Mallen, County Administrator	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County	Yuba County	Robert Bendorf, County Executive Officer	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County	Yuba County	Sean Powers, Director Of Finance & Administration	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY
(CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
County	Colusa County	Mike Azevedo, Director	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County	Colusa County	Wendy Tyler, CAO	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County	Contra Costa County	David Twa, County Administrator	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County	Contra Costa County	Gayle Israel, Chief of Staff	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County	Contra Costa County	Karen Mitchoff, Chair of the Board	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County Emergency Services	Alameda County Sheriffs Office of Emergency Services	Terri Langdon, Senior Emergency Services Coordinator	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County Emergency Services	Alameda County Sheriffs Office of Emergency Services, OES	Brentt Blaser, Senior Emergency Services Coordinator	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County Emergency Services	El Dorado County Fire Protection District	Tim Cordero, Fire Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
County Emergency Services	EMS	Benjamin Gammon, MHOAC	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County Emergency Services	EMS	Brenda Brenner, MHOAC	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County Emergency Services	EMS	Carly Sullivan, MHOAC	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County Emergency Services	EMS	Celia Sutton-Pado, Health Officer	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County Emergency Services	EMS	Chelsi Brown, MHOAC	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County Emergency Services	EMS	Clarence Teem, MHOAC	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County Emergency Services	EMS	Curtis Jack, MHOAC	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County Emergency Services	EMS	David Herfindahl, Health Officer	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County Emergency Services	EMS	Gail Newel, MHOAC	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
County Emergency Services	EMS	General MHOAC, MHOAC	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County Emergency Services	EMS	Jackie Lowther, EMS Director	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County Emergency Services	EMS	James Clark, MHOAC	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County Emergency Services	EMS	James Salvante, MHOAC	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County Emergency Services	EMS	Jared Bagwell, EMS Admin	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County Emergency Services	EMS	Jeff Fariss, MHOAC	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County Emergency Services	EMS	Jeffrey D'Andrea, MHOAC	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County Emergency Services	EMS	Jen Banks, MHOAC	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County Emergency Services	EMS	Jim Morrissey, EMS Disaster and WMD Coordinator	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
County Emergency Services	EMS	Jim Uruburu, MHOAC	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County Emergency Services	EMS	John Brown, EMS Director	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County Emergency Services	EMS	Jonathan Portney, Health Services Director	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County Emergency Services	EMS	Julie Vaishampayan, Health Officer	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County Emergency Services	EMS	Karen Haught, MHOAC	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County Emergency Services	EMS	Karen Relucio, MHOAC	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County Emergency Services	EMS	Ken Cutler, Health Officer	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County Emergency Services	EMS	Kristin Weivoda, MHOAC	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County Emergency Services	EMS	Kristina Miller, General	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
County Emergency Services	EMS	Marisol Torres, MHOAC	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County Emergency Services	EMS	Megan Montgomery, MHOAC	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County Emergency Services	EMS	MHOAC Duty Officer, MHOAC	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County Emergency Services	EMS	MHOAC EMS Duty Officer, MHOAC	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County Emergency Services	EMS	Michael Cabano, EMS Program Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County Emergency Services	EMS	Michelle Patterson, MHOAC	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County Emergency Services	EMS	Patti Carter, MHOAC	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County Emergency Services	EMS	Robert Herrick, MHOAC	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County Emergency Services	EMS	Shaun Vincent, MHOAC	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
County Emergency Services	EMS	Ted Mamoulelis, MHOAC	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County Emergency Services	EMS	Tiffany Rivera, MHOAC	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County Emergency Services	EMS	Travis Kusman, MHOAC	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County Emergency Services	EMS	Troy Mead, MHOAC	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County Emergency Services	EMS	Troy Peterson, MHOAC	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County Emergency Services	EMS	Vince Pierucci, EMS Division Director	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County Emergency Services	EMS	William McClurg, General	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County Emergency Services	Fire Department	Aaron McCallister, Deputy Fire Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County Emergency Services	Fire Department	Barry Biermann, Deputy Fire Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
County Emergency Services	Fire Department	Bill Amable, Battalion Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County Emergency Services	Fire Department	Bill Amable, Battalion Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County Emergency Services	Fire Department	Bobby Brand, Battalion Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County Emergency Services	Fire Department	Bonnie Terra, Division Chief/Fire Marshal	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County Emergency Services	Fire Department	Brian Helmick, Fire Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County Emergency Services	Fire Department	Central County Fire Department Burlingame Millbrae Hillsborough, Fire Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County Emergency Services	Fire Department	Central Marin Fire Authority, General	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County Emergency Services	Fire Department	Charlie Norman, Fire Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY
(CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
County Emergency Services	Fire Department	Chris Gerking, Fire Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County Emergency Services	Fire Department	Chuck Pompicpic, Deputy Fire Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County Emergency Services	Fire Department	Chuck Pompicpic, Deputy Fire Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County Emergency Services	Fire Department	Clyde Preston, Fire Safety Inspector	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County Emergency Services	Fire Department	Cyndi Foreman, Fire Prevention	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County Emergency Services	Fire Department	Dan Tafoya, Fire Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County Emergency Services	Fire Department	David Sargenti, General	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County Emergency Services	Fire Department	David Witt, Fire Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County Emergency Services	Fire Department	Eric Peterson, Fire Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
County Emergency Services	Fire Department	Fire Department Colusa, General	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County Emergency Services	Fire Department	Fire Department Dispatch Plumas County, Dispatch	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County Emergency Services	Fire Department	Fire Department Fresno County, Emergency	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County Emergency Services	Fire Department	Fire Department Fresno, Emergency	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County Emergency Services	Fire Department	Fire Department Huron, General	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County Emergency Services	Fire Department	Fire Department Lassen County, CAL FIRE	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County Emergency Services	Fire Department	Fire Department Madera County, Command Center	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County Emergency Services	Fire Department	Fire Department Marin County, Duty Officer	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County Emergency Services	Fire Department	Fire Department Marin County, General	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY
(CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
County Emergency Services	Fire Department	Fire Department Mariposa County, Emergency Command Center	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County Emergency Services	Fire Department	Fire Department Nevada County, General	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County Emergency Services	Fire Department	Fire Department Pleasanton, Non- Emergency	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County Emergency Services	Fire Department	Fire Department San Joaquin, General	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County Emergency Services	Fire Department	Fire Department San Luis Obispo County, Duty Officer	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County Emergency Services	Fire Department	Fire Department San Luis Obispo County, General	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County Emergency Services	Fire Department	Fire Department Santa Cruz, General	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County Emergency Services	Fire Department	Fire Department Tulare County, Dispatch Center	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County Emergency Services	Fire Department	Fire Department Tulare County, Duty Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
County Emergency Services	Fire Department	Fire Department Tuolumne County, Emergency Command Center	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County Emergency Services	Fire Department	Fire Department Tuolumne County, General	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County Emergency Services	Fire Department	Frank Drayton, Deputy Fire Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County Emergency Services	Fire Department	Fred Lopez, Division Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County Emergency Services	Fire Department	Gaudenz Panholzer, Fire Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County Emergency Services	Fire Department	Jason Weber, Non-Emergency	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County Emergency Services	Fire Department	John Walbridge, Fire Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County Emergency Services	Fire Department	Ken Mackey, Fire Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County Emergency Services	Fire Department	Lance Calkins, Fire Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
County Emergency Services	Fire Department	Lauri Smith, USFS PNF Dispatch	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County Emergency Services	Fire Department	Lewis Broschard, Fire Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County Emergency Services	Fire Department	Matt Gustafson, Deputy Fire Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County Emergency Services	Fire Department	Matt Powers, Battalion Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County Emergency Services	Fire Department	Matt Powers, Battalion Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County Emergency Services	Fire Department	Mike Waponowski, Fire Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County Emergency Services	Fire Department	Mrs. Chris Wilkes, General	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County Emergency Services	Fire Department	Mrs. Kerri Donis, Fire Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County Emergency Services	Fire Department	Plumas National Forest Dispatch center Plumas County, USFS PNF Dispatch	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
County Emergency Services	Fire Department	Ray Iverson, Fire Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County Emergency Services	Fire Department	Richard Dickinson, Fire Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County Emergency Services	Fire Department	Richard Murdock, County Fire Warden	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County Emergency Services	Fire Department	Ron Bravo, Deputy Fire Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County Emergency Services	Fire Department	Ron Myers, Fire Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County Emergency Services	Fire Department	Ross Macumber, Battalion Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County Emergency Services	Fire Department	Ruben Martin, Fire Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County Emergency Services	Fire Department	Ryan Frederick, Battalion Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County Emergency Services	Fire Department	Ryan Frederick, Battalion Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
County Emergency Services	Fire Department	Ryan Nishimoto, Division Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County Emergency Services	Fire Department	Tony Bowden, Fire Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County Emergency Services	Fire Department	Walter White, Fire Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County Emergency Services	Fire Department	William McDonald, Fire Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County Emergency Services	Fire Department	William Sapeta, Fire Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County Emergency Services	Fire Protection District	Chris Tubbs, Fire Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County Emergency Services	Mountain Valley EMS Agency	Mountain Valley EMS Agency Stanislaus County, EMS Duty Officer	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County Emergency Services	Napa Co Fire Dept/Cal Fire	geoff Belyea, Napa County Fire Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County Emergency Services	Napa Co Fire Dept/Cal Fire	Jason Martin, Napa County Fire Operations Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
County Emergency Services	Plumas Public Health	Lori Beatley, General	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County Emergency Services	Sheriff	Andrew Scott, Lieutenant - PCSO	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County Emergency Services	Sheriff	Brian Silva, Lieutenant - PCSO	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County Emergency Services	Sheriff	Dispatch Supervisor, Sheriff Dispatch	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County Emergency Services	Sheriff	Jason Lockhart, Lieutenant - PCSO	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County Emergency Services	Sheriff	Jeff Power, Sergeant - PCSO	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County Emergency Services	Sheriff	Josh Barnhart, Lieutenant - PCSO	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County Emergency Services	Sheriff	Kevin Griffiths, Sergeant - PCSO	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County Emergency Services	Sheriff	Shayne Wright, Lieutenant - PCSO	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
County Emergency Services	Sheriff	Sheriff Lassen County, General	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County Emergency Services	Sheriff	Ty Conners, Sergeant - PCSO	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County Emergency Services	Sheriff	Zach Poisez, Sergeant - PCSO	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County Emergency Services	Sheriff's Department	Brian Martin, Sheriff	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County Emergency Services	Sheriff's Department	Cullen Dodd, Under-Sheriff	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County Emergency Services	Sheriff's Department	Dave Ennes, Sargent	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County Emergency Services	Sheriff's Department	Eric Taylor, Sheriff	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County Emergency Services	Sheriff's Department	Gavin Wells, Lieutenant	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County Emergency Services	Sheriff's Department	Gregory Ahern, Sheriff	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
County Emergency Services	Sheriff's Department	Ian Parkinson, Sheriff	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County Emergency Services	Sheriff's Department	Jarret Benov, Sheriff	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County Emergency Services	Sheriff's Department	Jeff Dirkse, Sheriff	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County Emergency Services	Sheriff's Department	Jim Hart, Sheriff	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County Emergency Services	Sheriff's Department	Joe Hickerson, Communications Supervisor	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County Emergency Services	Sheriff's Department	Kory Honea, Sheriff	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County Emergency Services	Sheriff's Department	Margaret Mims, Sheriff	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County Emergency Services	Sheriff's Department	Mark Essick, Sheriff	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County Emergency Services	Sheriff's Department	Mark Padilla, Patrol Captain	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
County Emergency Services	Sheriff's Department	Mike Boudreaux, Sheriff	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County Emergency Services	Sheriff's Department	Mike Fisher, Sheriff	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County Emergency Services	Sheriff's Department	Mitchell Medina, Undersheriff	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County Emergency Services	Sheriff's Department	Oscar Ortiz, Sheriff	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County Emergency Services	Sheriff's Department	Patrick Withrow, Sheriff	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County Emergency Services	Sheriff's Department	Richard Warren, Sheriff	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County Emergency Services	Sheriff's Department	Sheriff's Department Alameda County, Technician	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County Emergency Services	Sheriff's Department	Sheriff's Department San Luis Obispo County, Watch Commander	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County Emergency Services	Sheriff's Department	Sheriff's Department Tuolumne County, Sheriff	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
County Emergency Services	Sheriff's Department	Steve Bernal, Sheriff	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County Emergency Services	Sheriff's Department	Thomas Ferrara, Sheriff	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County Emergency Services	Sheriff's Department	Todd Johns, Sheriff	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County Emergency Services	Sheriff's Department	Vern Warnke, Sheriff	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County Emergency Services	Sheriff's Department	William Honsal, Sheriff	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County Emergency Services	Sheriff's Dept	Andrew Cash, Sheriff's Liaison	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County Emergency Services	Sheriff's Office	Aaron Palmer, City Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County Emergency Services	Sheriff's Office	Autumn Long-McGie, Dispatch Supervisor	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County Emergency Services	Sheriff's Office	Bill Brown, Sheriff	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
County Emergency Services	Sheriff's Office	Carlos Bolanos, Non-Emergency	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County Emergency Services	Sheriff's Office	David Hencratt, OES Director	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County Emergency Services	Sheriff's Office	David Robinson, Dispatch	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County Emergency Services	Sheriff's Office	Denver Stoner, Public Safety Officer	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County Emergency Services	Sheriff's Office	Donny Youngblood, General	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County Emergency Services	Sheriff's Office	Griffin Dennis, Corrections Lieutenant	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County Emergency Services	Sheriff's Office	Jason Barnhart, Undersheriff	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County Emergency Services	Sheriff's Office	Kristie Mitchell, Public Information Officer	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County Emergency Services	Sheriff's Office	Matthew Kendall, Sheriff	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
County Emergency Services	Sheriff's Office	Michael Johnson, Sheriff	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County Emergency Services	Sheriff's Office	Miller Kevin, Operations Lieutenant	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County Emergency Services	Sheriff's Office	Mr. Tim Rumfelt, Special Operations	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County Emergency Services	Sheriff's Office	Pace Stokes, OES Capt	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County Emergency Services	Sheriff's Office	Rick DiBasilio, Non-Emergency	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County Emergency Services	Sheriff's Office	Rob Sandbloom, Lieutenant	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County Emergency Services	Sheriff's Office	Robert Doyle, General	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County Emergency Services	Sheriff's Office	Scott Smallwood, Undersheriff	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County Emergency Services	Sheriff's Office	Shannon Barney, Commander	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
County Emergency Services	Sheriff's Office	Sheriff Plumas County, Dispatch	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County Emergency Services	Sheriff's Office	Sheriff/Police/Fire/OES/EMS San Benito County, Non-Emergency	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County Emergency Services	Sheriff's Office	Sheriff's Office Alpine County, Dispatch	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County Emergency Services	Sheriff's Office	Sheriff's Office Buellton, Non-Emergency	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County Emergency Services	Sheriff's Office	Sheriff's Office Colfax, Substation	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County Emergency Services	Sheriff's Office	Sheriff's Office Kern County, Emergency	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County Emergency Services	Sheriff's Office	Sheriff's Office Loomis, Substation	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County Emergency Services	Sheriff's Office	Sheriff's Office Maricopa, Taft Substation	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County Emergency Services	Sheriff's Office	Sheriff's Office Mariposa County, Emergency Dispatch	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
County Emergency Services	Sheriff's Office	Sheriff's Office Nevada County, General	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County Emergency Services	Sheriff's Office	Sheriff's Office Rio Vista, Emergency	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County Emergency Services	Sheriff's Office	Sheriff's Office San Benito County, Non-Emergency	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County Emergency Services	Sheriff's Office	Sheriff's Office San Juan Bautista, Non-Emergency	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County Emergency Services	Sheriff's Office	Sheriff's Office Santa Cruz County, Non-Emergency	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County Emergency Services	Sheriff's Office	Sheriff's Office Solano County, Emergency	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County Emergency Services	Sheriff's Office	Sheriff's Office Solvang, Non-Emergency	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County Emergency Services	Sheriff's Office	Sheriff's Office Sonoma County, Sheriff Dispatch	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County Emergency Services	Sheriff's Office	Sheriff's Office Trinidad, Non-Emergency Dispatch	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY
(CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
County Emergency Services	Sheriff's Office	Sheriff's Office Tulare County, Dispatch Center, N/A	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County Emergency Services	Sheriff's Office	Sheriff's Office Wasco, Substation, N/A	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County Emergency Services	Sheriff's Office	Sheriff's Office Willows, Non-Emergency, N/A	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County Emergency Services	Sheriff's Office	Sheriff's Office Yolo County, Non-Emergency,	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County Emergency Services	Sheriff's Office	Smith Laurie, Non-Emergency	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County Emergency Services	Alameda County OES	Derrick Thomas, ACFD Div Chief / Emergency Management	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)
County Emergency Services	Alameda County OES	Kristi Duenas, OEE Emergency Services Coordinator	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
County Emergency Services	Alameda County OES	Lincoln Casimere, ACFD Emergency Manager	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)
County Emergency Services	Alameda County OES	Paul Stokes, Captain OES	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)
County Emergency Services	Alpine County OES	Tom Minder, OES Director/Sheriff	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)
County Emergency Services	Amador County OES	Jason Navarre OES Coordinator	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)
County Emergency Services	Butte County OES	Joshua Jimerfield, OES Director	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
County Emergency Services	Calaveras County OES	John Osbourn, OES Director	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)
County Emergency Services	Colusa County OES	Janice Bell, OES Coordinator	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)
County Emergency Services	Colusa County OES	Russ Jones, OES	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)
County Emergency Services	Colusa County OES	Cameron Bardwell, OES	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)
County Emergency Services	Contra Costa County OES	Duty Officer (24/7), On Call Contact	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
County Emergency Services	Contra Costa County OES	Rick Kovar, OES Director	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)
County Emergency Services	El Dorado County OES	El Dorado General	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)
County Emergency Services	El Dorado County OES	Moke Auwae, OES	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)
County Emergency Services	Fresno County OES	Brandon Pursell Sheriff	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)
County Emergency Services	Fresno County OES	Gabriel De La Cerda , Assitant OES Director	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY
(CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
County Emergency Services	Glenn County OES	Amy Travis, OES Director	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)
County Emergency Services	Humboldt County OES	Ryan Derby, OES Director	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)
County Emergency Services	Kern County OES	Georgianna Armstrong, OES Director	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)
County Emergency Services	Kings County OES	German Ortiz, OES	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)
County Emergency Services	OES	Gavin Wells, OES	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY
(CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
County Emergency Services	OES	Leah Sautelet, OES Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
County Emergency Services	Lassen County OES	Silas Rojas, OES Director	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)
County Emergency Services	Madera County OES	Joseph Wilder, OES Coordinator/Sergeant	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)
County Emergency Services	Madera County OES	Tyson Pogue, OES Director/Sheriff	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)
County Emergency Services	Marin County OES	Chris Reilly, OES Manager	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
County Emergency Services	Marin County OES	Marin Duty Officer Mailbox, on Call contact	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)
County Emergency Services	Marin County OES	Woody Baker-Cohn, OES Assist. Manager	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)
County Emergency Services	Mariposa County OES	Jeremy Briese, OES Director/Sheriff	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)
County Emergency Services	Mariposa County OES	Wes Smith, OES Coordinator/Sergeant	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)
County Emergency Services	Mendocino County OES	Garrett James, OES	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
County Emergency Services	Mendocino County OES	Brentt Blaser, OES Director	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)
County Emergency Services	Merced County OES	Adam Amaral, OES Coordinator	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)
County Emergency Services	Monterey County OES	Duty Officer (24/7), On Call contact, MC_Duty	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)
County Emergency Services	Monterey County OES	Gerry Malais, OES Director	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)
County Emergency Services	Monterey County OES	Kelsey Scanon OES	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
County Emergency Services	Monterey County OES	Justin Lin Monterey County OES	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)
County Emergency Services	Napa County OES	Leah Greenbaum, OES	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)
County Emergency Services	Napa County OES	Kerry Whitney, County Risk Manager	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)
County Emergency Services	Nevada County OES	Steve Monaghan, OES	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)
County Emergency Services	Nevada County OES	Paul Cummings, OES Deputy Director	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
County Emergency Services	Placer County OES	General, OES General Mail Box	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)
County Emergency Services	Plumas County OES	Pam Courtright, OES Coordinator	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)
County Emergency Services	Sacramento County OES	Matthew Hawkins, OES Director	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)
County Emergency Services	Sacramento County OES	Steve Cantelme, OES	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)
County Emergency Services	San Benito County OES	Kris Mangano, Emergency Services Manager	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
County Emergency Services	San Benito County OES	Madison Mitchell, Emergency Services Coordinator	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)
County Emergency Services	San Francisco County OES	Adrienne Bechelli, Deputy Director	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)
County Emergency Services	San Francisco County OES	DEM Duty Officer, On Call contact	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)
County Emergency Services	San Francisco County OES	Francis Zamora, Chief of Staff	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)
County Emergency Services	San Francisco County OES	Jodi Traversaro , UASI Liaison	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
County Emergency Services	San Francisco County OES	Victor Lim, External Affairs Officer	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)
County Emergency Services	San Joaquin County	Tiffany Heyer, OES Director of Emergency Services	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)
County Emergency Services	San Luis Obispo County	Duty Officer, Duty Officer	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)
County Emergency Services	San Luis Obispo County	Joe Guzzardi, OES	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)
County Emergency Services	San Luis Obispo County	Scotty Jalbert, Emergency Services Manager	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
County Emergency Services	San Mateo County	Don Mattie, Director	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)
County Emergency Services	San Mateo County	Jeff Norris, DEM Coordinator	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)
County Emergency Services	Santa Barbara County	Kelly Hubbard, OEM Director	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)
County Emergency Services	Santa Clara County OES	Dana Reed, Director	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)
County Emergency Services	Santa Clara County OES	Darrell Ray Jr., Deputy Director	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)

**TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY
(CONTINUED)**

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
County Emergency Services	Santa Cruz County OES	David Reid, Director	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)
County Emergency Services	Santa Cruz County OES	Michael Beaton, Director General Services	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)
County Emergency Services	Santa Cruz County OES	Lisa Ehret, OES	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)
County Emergency Services	Santa Cruz County OES	Michael Bennett, OES	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)
County Emergency Services	Shasta County OES	Dave Renfer, OES Officer	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
County Emergency Services	Shasta County OES	Rob Sandbloom, OES Director	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)
County Emergency Services	Sierra County OES	Lee Brown, OES Director	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)
County Emergency Services	Siskiyou County OES	Bryan Schenone, OES Director	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)
County Emergency Services	Solano County OES	Donald Ryan, OES Director	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)
County Emergency Services	Sonoma County OES	Christopher Godley, DEM Director	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
County Emergency Services	Sonoma County OES	Emergency Management, DEM General Inbox	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)
County Emergency Services	Sonoma County OES	Jeff Duvall, DEM Deputy Director	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)
County Emergency Services	Sonoma County OES	Sam Wallis, DEM Community Warning	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)
County Emergency Services	Stanislaus County OES	Richard Murdock, Fire Marshall	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)
County Emergency Services	Stanislaus County OES	Shannon Williams, OES	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY
(CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
County Emergency Services	Stanislaus County OES	Ron Reid, County OES	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)
County Emergency Services	Sutter County OES	Zach Hamill, OES Director	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)
County Emergency Services	Tehama County OES	Andy Houghtby, OES Director	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)
County Emergency Services	Trinity County OES	Mike Cottone, OES	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)
County Emergency Services	Tulare County OES	Andrew Lockman, Emergency Services Manager	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
County Emergency Services	Yuba County OES	Dore Bietz, OES Coordinator	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)
County Emergency Services	Yuba County OES	Kristin Weivoda, OES	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)
County Emergency Services	Yuba County	John Stone, OES Deputy Director	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)
County Emergency Services	Yuba County OES	Oscar Marin, OES Director	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)
Emergency Hospitals	Alameda County Medical Center	Kristen Thorson	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
Emergency Hospitals	Alameda County Medical Center	Jose (Ramses)	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Emergency Hospitals	Alameda County Medical Center	Mpa,vivian Nguyen	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Emergency Hospitals	California Pacific Medical Center	Mike Featherstone	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Emergency Hospitals	California Pacific Medical Center	Celena Galicial	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Emergency Hospitals	California Pacific Medical Center	Kwame Inkabi	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Emergency Hospitals	Enloe Medical Center	Bill Seguine	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Emergency Hospitals	Enloe Medical Center	Brian Reimer	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Emergency Hospitals	Enloe Medical Center	Kevin Vandervelden	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Emergency Hospitals	Glenn Medical Center	Randy Castle	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
Emergency Hospitals	Marshall Medical Center	Marshall Medical	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Emergency Hospitals	Marshall Medical Center	Greg Trapani	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Emergency Hospitals	Natividad Medical Center	Will Signorelli	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Emergency Hospitals	Natividad Medical Center	Jeff Cleek	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Emergency Hospitals	Queen Of The Valley Medical Center	Keith Dahl	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Emergency Hospitals	Santa Clara Valley Medical Center	Ryan Pruitt	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Emergency Hospitals	Santa Clara Valley Medical Center	Hospital Stationary	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Emergency Hospitals	Summit Medical Center	Angel Borja	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Emergency Hospitals	Summit Medical Center	Rafael Vargas	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY
(CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
Emergency Hospitals	Sutter Bay Medical Foundation	Greg Mills	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Emergency Hospitals	Sutter Delta Medical Center	Tim Bouslog	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Emergency Hospitals	Sutter Solano Medical Center	Mike Boyce	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Emergency Hospitals	American Hospital Management Corp	Pam Floyd	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Emergency Hospitals	American Hospital Management Corp	David Neal	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Emergency Hospitals	El Camino Hospital Inc	Ken King	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Emergency Hospitals	El Camino Hospital Inc	Paul Bonitz	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Emergency Hospitals	El Camino Hospital Inc	Marty Kobaly	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Emergency Hospitals	Hca Good Samaritan Hospital	Robert (Rob)	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
Emergency Hospitals	Hca Good Samaritan Hospital	Tom San	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Emergency Hospitals	Hca Good Samaritan Hospital	Gary Purushothan	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Emergency Hospitals	Heart Hospital Of Bk Llc	Ezequiel Esquivel	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Emergency Hospitals	Heart Hospital Of Bk Llc	Joe Aguirre	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Emergency Hospitals	Heart Hospital Of Bk Llc	Omar Miranda	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Emergency Hospitals	John C Fremont Hospital	Nanette Wardle	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Emergency Hospitals	John C Fremont Hospital	Terry Woodward	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Emergency Hospitals	Kaiser Foundation Hospitals Inc	John Thompson	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Emergency Hospitals	Kaiser Foundation Hospitals Inc	Janis Cruz	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
Emergency Hospitals	Kern County Hospital Authority	Anthony Michael	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Emergency Hospitals	Marin General Hospital	Shawn Mann	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Emergency Hospitals	Marin General Hospital	Vernon Moreno	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Emergency Hospitals	Marin General Hospital	Darren Nakatani	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Emergency Hospitals	Mark Twain St Joseph's Hospital	Craig Carter	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Emergency Hospitals	Mark Twain St Joseph's Hospital	Ed Gonzalez	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Emergency Hospitals	Mark Twain St Joseph's Hospital	Bill Wennhold	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Emergency Hospitals	Mayers Memorial Hospital	Alex Johnson	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Emergency Hospitals	Mayers Memorial Hospital	Valerie Lakey	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
Emergency Hospitals	Nme Hospitals Inc	Ann Lucena	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Emergency Hospitals	Nme Hospitals Inc	Andrew Nice	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Emergency Hospitals	Nme Hospitals Inc	Caryn Thornburg	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Emergency Hospitals	Oroville Hospital	James Campbell	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Emergency Hospitals	Oroville Hospital	Darrin Kean	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Emergency Hospitals	Oroville Hospital	Corbin Penman	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Emergency Hospitals	Petaluma Valley Hospital	Matt Huddleston	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Emergency Hospitals	Plumas District Hospital (State Agency)	Shaun Priore	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Emergency Hospitals	Plumas District Hospital (State Agency)	Darren Beatty	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
Emergency Hospitals	Plumas District Hospital (State Agency)	Zoey Stancer	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Emergency Hospitals	Redwood Memorial Hospital	Jake Bolton	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Emergency Hospitals	San Benito Hospital District	Robert Ortega	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Emergency Hospitals	San Benito Hospital District	Tina Pulido	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Emergency Hospitals	San Benito Hospital District	Frank Gee	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Emergency Hospitals	Santa Ynez Valley Hospital	Nick Henderson	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Emergency Hospitals	Santa Ynez Valley Hospital	Ruben Gomez	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Emergency Hospitals	Santa Ynez Valley Hospital	Judy Blokdyke	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Emergency Hospitals	Seneca District Hospital	Kacie Broussard	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
Emergency Hospitals	Seneca District Hospital	Linda Mccurdy	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Emergency Hospitals	Seneca District Hospital	Lyndsey Theobald	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Emergency Hospitals	Sierra Nevada Memorial Hospital	Sue Urban	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Emergency Hospitals	Sierra Nevada Memorial Hospital	Calob Rangel	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Emergency Hospitals	Sierra Vista Hospital Inc	Eleze Armstrong	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Emergency Hospitals	Sierra Vista Hospital Inc	Rnemma Lauriston	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Emergency Hospitals	Sonoma Valley Hospital District	Grigory Gatenian	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Emergency Hospitals	Sonora Community Hospital	Evan Kalas	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Emergency Hospitals	Sonora Community Hospital	Ed Sullen	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
Emergency Hospitals	Southern Monterey County Memorial Hospital	Hospital Emergency	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Emergency Hospitals	Southern Monterey County Memorial Hospital	Jonathan Estey	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Emergency Hospitals	St Helena Hospital	Nursing Supervisor	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Emergency Hospitals	St Helena Hospital	Scott Sandin	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Emergency Hospitals	St Joseph Hospital	Sherie Henderson-Bialous	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Emergency Hospitals	St Joseph Hospital	Roberta Luskin-Hawk	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Emergency Hospitals	St Luke's Hospital	Robert Ray	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Emergency Hospitals	St Luke's Hospital	Rafael Preciado	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Emergency Hospitals	Sutter Amador Hospital	Sutter Health	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
Emergency Hospitals	Sutter Amador Hospital	Rick Clemons	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Emergency Hospitals	Sutter Bay Hospitals	Lazaro Rojas	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Emergency Hospitals	Sutter Bay Hospitals	Megan Stevenson	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Emergency Hospitals	Sutter Lakeside Community Hospital Inc	Dan Peterson	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Emergency Hospitals	Sutter Lakeside Community Hospital Inc	Shems Duty	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Emergency Hospitals	Sutter Tracy Community Hospital	Jason Simmons	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Emergency Hospitals	Sutter Tracy Community Hospital	Jimmy Rinaldo	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Emergency Hospitals	Sutter West Bay Hospital	Shannon Culpert	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Emergency Hospitals	Sutter West Bay Hospital	Jeff Miller	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
Emergency Hospitals	Sutter West Bay Hospital	Dawit Tesfasilassie	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Emergency Hospitals	Sutter West Bay Hospital	Wayne Bader	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Emergency Hospitals	Twin Cities Community Hospital Inc	Kaitlyn Cross	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Emergency Hospitals	Twin Cities Community Hospital Inc	Mike Lane	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Emergency Hospitals	Twin Cities Community Hospital Inc	Rick Ford	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Emergency Hospitals	Twin Cities Community Hospital Inc	Carrie Vucasovich	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Federal Agency	Army Corps of Engineers	Army Corps of Engineers EOC, EOC Email	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Federal Agency	Army Corps of Engineers	Army Corps of Engineers EOC, EOC Email	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Federal Agency	Army Corps of Engineers	Josh Jimerfield, USACE Sacramento Office	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
Federal Agency	Department of Health Service	Rita Kerr, Health Officer	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Federal Agency	Department of Health Services	James Salvante, EMS	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Federal Agency	Department of Health Services	Mike Romero, Public Health Officer	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Federal Agency	Department of Health Services	Phuong Luu, Health Officer	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Federal Agency	Department of Health Services	Richard Johnson, Health Officer	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Federal Agency	Department of Health Services	Sundari Mase, Public Health Officer	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Federal Agency	Department of IT	Peter Owen, IT Director	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Federal Agency	Department of Public Safety	Dan Moskowitz, General	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Federal Agency	Department of Public Safety	Norma Amaro, General	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
Federal Agency	Department of Veteran Affairs	Shannondor Marquez, Director, Emergency Management, Environmental Health & Safety	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Federal Agency	Dept of Transp, Federal Transit Admin	James Baxmeyer, Admin Officer	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Federal Agency	FBI	J Isaacson, COS	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Federal Agency	Federal Communications Commission	Jennifer Holtz, Deputy Division Chief, Cybersecurity and Communications Reliability Division	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Federal Agency	Federal Communications Commission	Justin Cain, Chief, Operations and Emergency Management Division	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Federal Agency	Federal Emergency Management Agency	Christine Borgognoni, Preparedness and Analysis Branch Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Federal Agency	Federal Emergency Management Agency	Toni Knight, Planning Section Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Federal Agency	Housing and Urban	HUD General, Region 9 Administrator	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
	Development (HUD)					
Federal Agency	U.S. Army	Army General, General	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Federal Agency	U.S. Army 63rd Division	Lt. Col. Gerald Hall, EOC lead	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Federal Agency	U.S. Army Reserves	Aaron Decapua, Communications Director	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Federal Agency	U.S. Bureau of Reclamation	Daniel Villanueva, Occupational Safety, Health, and Emergency Mgmt. Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Federal Agency	U.S. Coast Guard Sector San Francisco	Libby Rasmussen, Emergency Manager & Force Readiness Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Federal Agency	U.S. Department of Health & Human Services	Schuyler Hall, Outreach and Policy Specialist, Officer of the Director, Region IX	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Federal Agency	U.S. Department of Homeland Security	Frank Calvillo, Director, Region IX	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Federal Agency	U.S. Department of Homeland Security	Jesse Rangle, Protective Security Advisor, Cyber and Infrastructure Security Agency, Region IX	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
Federal Agency	U.S. Department of the Interior	General Dept. of Interior, General	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Federal Agency	U.S. Department of the Interior	General Dept. of Interior, General,	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Federal Agency	U.S. Dept. of Housing & Urban Development	Barbara Arch, Supervisory Mgmt. Analyst	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Federal Agency	U.S. Environmental Protection Agency	Kenneth Wysocki, Assistant Director, Drinking Water Division	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Federal Agency	U.S. EPA	Jason Musante, Federal On-Scene Coordinator	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Federal Agency	United States Coast Guard	Lauren Cefali, Contingency Planning	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Federal Agency	US Coast Guard Eleventh District	Romulus Matthews, Commander, Contingency Planning	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Federal Agency	US Department of Agriculture	Chris French, Acting Deputy Under Secretary, Natural Resources and the Environment,	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
Federal Agency	US Department of Agriculture	Christine Dawe, Acting Associate Deputy Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Federal Agency	US Department of Defense	Lisa Jung, Deputy Assistant Secretary	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Federal Agency	US Department of Energy	Tarak Shah, Chief of Staff, Office of the Secretary	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Federal Agency	US Forest Service	Jacob Donnay, Legislative Affairs	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Federal Agency	US Forest Service	Jeffrey Bradshaw, Safety & Occupational Health Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Federal Agency	US Forest Service Fire	Audrey Dalrymple, Dispatch	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Federal Agency	US Forest Service Fire	Luis Gomez, Deputy Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Federal Agency	US Forest Service Fire	Michael Davis, Division Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Federal Agency	US Forest Service Fire	Shannon Banks, Battalion Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
Federal Agency	US Forest Service Fire	Terry Nickerson, Division Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Federal Emergency Services	Coast Guard	Erin O'Donnell, Pacific Area Incident Management	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Federal Emergency Services	PHI Air Medical	Erin Cox, General	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Publicly-Owned Utilities	Community Clean Energy	Lori Mitchel, Director Clean Energy	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Publicly-Owned Utilities	East Bay Community Energy	Alex DiGiorgio (Alameda), General	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Publicly-Owned Utilities	East Bay Community Energy	Cait Cady (Alameda), General	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Publicly-Owned Utilities	East Bay Community Energy	Kelly Brezovec (Alameda), Customer Care Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Publicly-Owned Utilities	MCE Clean Energy	Bill Rus (Contra Costa), Data Architect	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Publicly-Owned Utilities	MCE Clean Energy	Bill Rus (Marin), Data Architect	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
Publicly-Owned Utilities	MCE Clean Energy	Bill Rus (Napa), Data Architect	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Publicly-Owned Utilities	MCE Clean Energy	Bill Rus (Solano), Data Architect	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Publicly-Owned Utilities	MCE Clean Energy	Daniel Genter (Contra Costa), Data Analyst	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Publicly-Owned Utilities	MCE Clean Energy	Daniel Genter (Marin), Data Analyst	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Publicly-Owned Utilities	MCE Clean Energy	Daniel Genter (Napa), Data Analyst	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Publicly-Owned Utilities	MCE Clean Energy	Daniel Genter (Solano), Data Analyst	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Publicly-Owned Utilities	MCE Clean Energy	Dawn Weisz (Contra Costa), CEO	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Publicly-Owned Utilities	MCE Clean Energy	Dawn Weisz (Marin), CEO	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Publicly-Owned Utilities	MCE Clean Energy	Dawn Weisz (Napa), CEO	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY
(CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
Publicly-Owned Utilities	MCE Clean Energy	Dawn Weisz (Solano), CEO	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Publicly-Owned Utilities	MCE Clean Energy	Enyonam Senyo-Mensah (Contra Costa), Office Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Publicly-Owned Utilities	MCE Clean Energy	Enyonam Senyo-Mensah (Marin), Office Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Publicly-Owned Utilities	MCE Clean Energy	Enyonam Senyo-Mensah (Napa), Office Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Publicly-Owned Utilities	MCE Clean Energy	Enyonam Senyo-Mensah (Solano), Office Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Publicly-Owned Utilities	MCE Clean Energy	Justine Parmelee (Contra Costa), Manager of Administrative Services	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Publicly-Owned Utilities	MCE Clean Energy	Justine Parmelee (Marin), Manager of Administrative Services	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Publicly-Owned Utilities	MCE Clean Energy	Justine Parmelee (Napa), Manager of Administrative Services	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Publicly-Owned Utilities	MCE Clean Energy	Justine Parmelee (Solano), Manager of Administrative Services	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
Publicly-Owned Utilities	MCE Clean Energy	Vicken Kasarjian (Contra Costa), Chief Operating Officer	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Publicly-Owned Utilities	MCE Clean Energy	Vicken Kasarjian (Marin), Chief Operating Officer	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Publicly-Owned Utilities	MCE Clean Energy	Vicken Kasarjian (Napa), Chief Operating Officer	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Publicly-Owned Utilities	MCE Clean Energy	Vicken Kasarjian (Solano), Chief Operating Officer	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Publicly-Owned Utilities	MCE Clean Energy	Zae Perrin (Contra Costa), Manager of Customer Operations	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Publicly-Owned Utilities	MCE Clean Energy	Zae Perrin (Marin), Manager of Customer Operations	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Publicly-Owned Utilities	MCE Clean Energy	Zae Perrin (Napa), Manager of Customer Operations	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Publicly-Owned Utilities	MCE Clean Energy	Zae Perrin (Solano), Manager of Customer Operations	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Publicly-Owned Utilities	Monterey Bay Community Power	Mary Federico (Monterey), Financial Analyst I,	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY
(CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
Publicly-Owned Utilities	Monterey Bay Community Power	Mary Federico (San Benito), Financial Analyst I,	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Publicly-Owned Utilities	Monterey Bay Community Power	Mary Federico (San Luis Obispo), Financial Analyst I,	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Publicly-Owned Utilities	Monterey Bay Community Power	Mary Federico (Santa Barbara), Financial Analyst I,	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Publicly-Owned Utilities	Monterey Bay Community Power	Mary Federico (Santa Cruz), Financial Analyst I,	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Publicly-Owned Utilities	Peninsula Clean Energy	Leslie Brown (San Mateo), Director of Customer Care	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Publicly-Owned Utilities	Peninsula Clean Energy	Michael Totah (San Mateo), Key Accounts Executive	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Publicly-Owned Utilities	Pioneer Community Energy	Alexia Retallack (El Dorado), Marketing and Government Affairs Manager,	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Publicly-Owned Utilities	Pioneer Community Energy	Alexia Retallack (Placer), Marketing and Government Affairs Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Publicly-Owned Utilities	Pioneer Community Energy	Mark Riffey (El Dorado), Director of Public Affairs, Marketing, and Programs,	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY
(CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
Publicly-Owned Utilities	Pioneer Community Energy	Mark Riffey (Placer), Director of Public Affairs, Marketing, and Programs,	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Publicly-Owned Utilities	Redwood Energy	Mahayla Slackerelli (Humboldt), Account Services Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Publicly-Owned Utilities	Redwood Energy	Nancy Stephenson (Humboldt), General	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Publicly-Owned Utilities	Redwood Energy	Richard Engel (Humboldt), Director of Power Resources	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Publicly-Owned Utilities	Redwood Energy	Sally Regali (Humboldt), Account Services Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Publicly-Owned Utilities	San Francisco Public Utilities	Josh Gale (San Francisco), Emergency Planning and Security	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Publicly-Owned Utilities	San Francisco Public Utilities	Justin Pine (San Francisco), Utility Specialist CleanPowerSF	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Publicly-Owned Utilities	San Jose Clean Energy	Joe Flores (Santa Clara), Deputy Director	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Publicly-Owned Utilities	San Jose Clean Energy	Kate Ziemba (Santa Clara), Public Information Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY
(CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
Publicly-Owned Utilities	San Jose Clean Energy	Mark Bachman (Santa Clara), Account Services Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Publicly-Owned Utilities	San Jose Clean Energy	Zach Struyk (Santa Clara), Deputy Director Account Management and Marketing	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Publicly-Owned Utilities	Silicon Valley Clean Energy	Don Bray (Santa Clara), Account Services and Community Relations Director	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Publicly-Owned Utilities	Silicon Valley Clean Energy	Pamela Leonard (Santa Clara), Communications Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Publicly-Owned Utilities	Sonoma Clean Power	Danielle McCants (Mendocino), Senior Customer Care Specialist	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Publicly-Owned Utilities	Sonoma Clean Power	Danielle McCants (Sonoma), Senior Customer Care Specialist	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Publicly-Owned Utilities	Sonoma Clean Power	Erica Torgerson (Mendocino), Director of Customer Care	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Publicly-Owned Utilities	Sonoma Clean Power	Erica Torgerson (Sonoma), Director of Customer Care	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Publicly-Owned Utilities	Sonoma Clean Power	Geof Syphers (Mendocino), CEO	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY
(CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
Publicly-Owned Utilities	Sonoma Clean Power	Geof Syphers (Sonoma), CEO	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Publicly-Owned Utilities	Sonoma Clean Power	Nathan Kinsey (Mendocino), Account Executive	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Publicly-Owned Utilities	Sonoma Water	Grant Davis, General	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Publicly-Owned Utilities	Sonoma Water	Steven Hancock, Emergency Manager	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Publicly-Owned Utilities	Valley Clean Energy	Alisa Lembke (Yolo), Board Clerk/Administrative Analyst	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Publicly-Owned Utilities	Valley Clean Energy	Edward Burnham (Yolo), Director of Finance & Internal Operations	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Publicly-Owned Utilities	Valley Clean Energy	Rebecca Boyles (Yolo), Director Customer Care and Marketing	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Publicly-Owned Utilities	Western Area Power Administration	Jeanne Haas, Utility Industry Restructuring Advisor	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
State Agency	Indian Health Service California Area	Carolyn Garcia, Director EHSS	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise	Functional Exercise (3/27/23 to

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
					(6/13/22 to 6/17/22)	3/31/23) Table-Top Exercise (6/6/23)
State Agency	State Government	Erin Dunn, State Assemblymember	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
State Agency	State Government	Thomas Wital, State Senator	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
State Emergency Services	CAL FIRE	Bret Gouvea, Chief, County Fire Warden	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)
State Emergency Services	CAL FIRE	Brian Estes, Chief	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)
State Emergency Services	CAL FIRE	Brian Estes, Local Cal Fire	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
State Emergency Services	CAL FIRE	CAL FIRE Butte County, Fire Chief,	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)
State Emergency Services	CAL FIRE	CAL FIRE Butte County, General CAL FIRE	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)
State Emergency Services	CAL FIRE	CAL FIRE Placer County, Emergency Command Center	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)
State Emergency Services	CAL FIRE	CAL FIRE San Luis Obispo County, Duty Chief	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)
State Emergency Services	CAL FIRE	Cal FIRE Shasta County, ECC,	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
State Emergency Services	CAL FIRE	CAL FIRE Tuolumne County, Local Cal Fire	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)
State Emergency Services	CAL FIRE	David Fulcher, Fire Chief	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)
State Emergency Services	CAL FIRE	Dispatch CAL FIRE TCU, Local Cal Fire,	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)
State Emergency Services	CAL FIRE	Dustin Hail, Unit Chief	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)
State Emergency Services	CAL FIRE	Duty Chief, Duty Chief	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
State Emergency Services	CAL FIRE	Eddy Moore, Local Cal Fire	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)
State Emergency Services	CAL FIRE	Garrett Sjolund, Division Chief	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)
State Emergency Services	CAL FIRE	George Gonzalez, Local Cal Fire	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)
State Emergency Services	CAL FIRE	George Morris III, Local Cal Fire	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)
State Emergency Services	CAL FIRE	Gratain Bidart, Acting Chief	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
State Emergency Services	CAL FIRE	Ian Larkin, Local Cal Fire,	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)
State Emergency Services	CAL FIRE	John Slate, Duty Chief	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)
State Emergency Services	CAL FIRE	Ken Lowe, Division Chief	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)
State Emergency Services	CAL FIRE	LNU Dispatch Lake County, Dispatch	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)
State Emergency Services	CAL FIRE	Mark Kendall, Chief, Northern Operations	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
State Emergency Services	CAL FIRE	Matt Streck, Division Chief	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)
State Emergency Services	CAL FIRE	Mike Blankenheim, Local Cal Fire	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)
State Emergency Services	CAL FIRE	Mike Marcucci, Local Cal Fire	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)
State Emergency Services	CAL FIRE	Mike Marcucci, Unit Chief	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)
State Emergency Services	CAL FIRE	Mike van Loben Sels, Unit Chief	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
State Emergency Services	CAL FIRE	Mr. Kurt McCray, Local Cal Fire	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)
State Emergency Services	CAL FIRE	Nate Armstrong, Cal-Fire Unit Chief CZU	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)
State Emergency Services	CAL FIRE	Patrick Purvis, Division Chief	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)
State Emergency Services	CAL FIRE	Reno Ditullio Jr., Fire Chief	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)
State Emergency Services	CAL FIRE	Robert Withrow, Unit Chief	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
State Emergency Services	CAL FIRE	Ryan Woessner, Battalion Chief	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)
State Emergency Services	CAL FIRE	Scott Lindgren, Local Cal Fire	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)
State Emergency Services	CAL FIRE	Sean Norman, Division Chief	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)
State Emergency Services	CAL FIRE	St. Helena Emergency Command Center, LNU Command Center	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)
State Emergency Services	CAL FIRE	Steve Walker, Division Chief	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY
(CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
State Emergency Services	CAL FIRE	David Fulcher, Fire Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
State Emergency Services	CAL FIRE	George Nunez, Cal Fire Battalion Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
State Emergency Services	CAL FIRE	John Owens, Deputy Fire Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
State Emergency Services	CAL FIRE	Mike Van Loben Sels, Cal FIRE Chief	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
State Emergency Services	CAL FIRE	Phillip Anzo, CAL FIRE	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
State Emergency Services	CAL FIRE TCU	Nick Casci, Unit Chief	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)
State Emergency Services	CALFIRE/ECC	Steve Mueller, Battalion Chief	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
State Emergency Services	CALFIRE/PCF	Bob Counts, Battalion Chief	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)
State Emergency Services	CALFIRE/PCF	Brian Eagan, Battalion Chief	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)
State Emergency Services	CALFIRE/PCF	Brian Mackwood, Assistant Chief	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)
State Emergency Services	CALFIRE/PCF	Jesse Morris, Battalion Chief	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)
State Emergency Services	CALFIRE/PCF	Jim Hudson, Deputy Chief	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
State Emergency Services	CALFIRE/PCF	Jon Woody, Battalion Chief	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)
State Emergency Services	California Highway Patrol	CHP Emergency Alert 24/7 Contact, General	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
State Emergency Services	California Office of Emergency Services	Adam Amaral, Emergency Services Coordinator	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)
State Emergency Services	CHP Golden Gate Division Dispatch	CHP Solano County, Emergency, N/A	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Telecommunications Providers	Altice/Suddenlink	Jason Oeklers	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)
Telecommunications Providers	Altice/Suddenlink	Luke Lundberg	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23)

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
						Table-Top Exercise (6/6/23)
Telecommunications Providers	Altice/Suddenlink	Ron Wilson	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)
Telecommunications Providers	American Tower	ATC	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Telecommunications Providers	American Tower	Trent Huffines	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Telecommunications Providers	American Tower	Darren Stahl	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Telecommunications Providers	AT&T	Adam Bensaid	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)
Telecommunications Providers	AT&T	Paul G Magoolaghan	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
Telecommunications Providers	AT&T	Fran Fatigati	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)
Telecommunications Providers	AT&T	John Goddard	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)
Telecommunications Providers	AT&T	Mark Innes	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)
Telecommunications Providers	AT&T	Joshua Mathisen	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)
Telecommunications Providers	AT&T	Jeff Mondon	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
Telecommunications Providers	AT&T	Josh Overton	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)
Telecommunications Providers	AT&T	Kevin Quinn	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)
Telecommunications Providers	AT&T	Maryanne Sawi	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)
Telecommunications Providers	AT&T	Joshua Overton	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)
Telecommunications Providers	Broadwing Communications, LLC	Tim Lafreniere	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY
(CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
Telecommunications Providers	Calaveras Telephone Co	Alvin Broglio	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Telecommunications Providers	Calneva	Tom Gelardi	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Telecommunications Providers	Caltel	Rich Ablos	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Telecommunications Providers	Charter Communications	Shannon Chapman	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)
Telecommunications Providers	Charter Communications	Greg Leming	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)
Telecommunications Providers	Charter Communications	Brad Shely	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
Telecommunications Providers	Comcast	Jason Aguas	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)
Telecommunications Providers	Comcast	Steven Belluzzi	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)
Telecommunications Providers	Comcast	Darrell Johnson	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)
Telecommunications Providers	Comcast	Steven Customer	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)
Telecommunications Providers	Comcast	Joseph Leto	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
Telecommunications Providers	Comcast	Jeff Votaw	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)
Telecommunications Providers	Consolidated Communications	Todd Ledesma	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Telecommunications Providers	Crown Castle	Wesley Jones	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Telecommunications Providers	Extenet	Lea Parker	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Telecommunications Providers	Foresthill Telephone	Sebastian Noc	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Telecommunications Providers	Foresthill Telephone	Rudy Cubillos	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Telecommunications Providers	Frontier Communications	Frontier	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Telecommunications Providers	Frontier Communications	Charlie Born	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
Telecommunications Providers	Frontier Communications	Nora Garrido	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Telecommunications Providers	Frontier Communications	Robert Rojas	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Telecommunications Providers	Frontier Communications	Thomas Turman	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Telecommunications Providers	Frontier Communications	Daryl Hayes	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Telecommunications Providers	Frontier Communications	Tim Watts	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Telecommunications Providers	Frontier Communications	Nora Garrido	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Telecommunications Providers	Happy Valley Telephone Co	Tom Johnston	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Telecommunications Providers	Happy Valley Telephone Co	Cory Pittman	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Telecommunications Providers	Hornitos Telephone Co C/O Tds Telecom	Heath Brower	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
Telecommunications Providers	Hornitos Telephone Co C/O Tds Telecom	Nichole Kosier	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Telecommunications Providers	Mediacom California Llc	Shawn Swatosh	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Telecommunications Providers	Mediacom California Llc	Tim Brown	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Telecommunications Providers	Northland Cable Television Inc	Liza Springer	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Telecommunications Providers	Northland Communications	Micah Martin	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Telecommunications Providers	Northland Communications	Ken Musgrove	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Telecommunications Providers	Ponderosa Telephone Co	Jim Dunn	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Telecommunications Providers	Ponderosa Telephone Co	Doug Wickham	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Telecommunications Providers	Qwest/Centurylink	Amy Schmidt	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
Telecommunications Providers	Qwest/Centurylink	Shanna Spring	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Telecommunications Providers	Sba Towers	Michael Fuller	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Telecommunications Providers	Sebastian Corp	Stephen Geringer	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Telecommunications Providers	Sierra Tel Co Inc	Sierra Telephone	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)
Telecommunications Providers	Sierra Telephone	Eyan Linn	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)
Telecommunications Providers	Sierra Telephone	Michael Montgomery	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
Telecommunications Providers	Sierra Telephone	Debbie Peters	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)
Telecommunications Providers	Sierra Telephone	Anthony Sternburg	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)
Telecommunications Providers	Sprint Corporation	Sprint	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Telecommunications Providers	Sprint Spectrum Lp	Sprint	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Telecommunications Providers	Tds Telecom	Michael Brinkley	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Telecommunications Providers	T-Mobile	Justin Clayden	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Telecommunications Providers	T-Mobile	Dan Paul	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
Telecommunications Providers	US Cellular	PSPS Notifications	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Telecommunications Providers	US Cellular	Chris Balfour	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Telecommunications Providers	US Cellular	John Maudlin	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Telecommunications Providers	Verizon	Gennie Barr	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Telecommunications Providers	Verizon	David Schultz	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Telecommunications Providers	Volcano Communications	Jonathan James	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Telecommunications Providers	Volcano Vision, Inc.	John Lundgren	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Telecommunications Providers	Volcano Vision, Inc.	Ray Bosstalk	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Telecommunications Providers	Wave Broadband	Shawn Thomas	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY
(CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
Transportation Agencies	BART	Bart Operations Control Center	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)
Transportation Agencies	Fresno Transportation Agency	PSPS-Public Works	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Transportation Agencies	Petaluma Transportation Authority	Cindy Chong	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Transportation Agencies	Petaluma Transportation Authority	Jim Castle	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Transportation Agencies	San Leandro Transportation Authority	City Of	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Transportation Agencies	San Leandro Transportation Authority	Catrina Christian	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Transportation Agencies	San Leandro Transportation Authority	Debbie Pollart	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Transportation Agencies	Santa Clara Transportation Authority	Customer Roads	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
Transportation Agencies	Santa Clara Transportation Authority	Customer 24 Hours	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Transportation Agencies	Solano Transportation Authority	James Bezek	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Transportation Agencies	Sonoma County Transportation Authority	Omar Daaboul	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Transportation Agencies	Sonoma County Transportation Authority	John Stout	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Transportation Agencies	Yolo County Transportation District	Customer Outages	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Transportation Agencies	Yolo County Transportation District	Arthur Robles	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Transportation Agencies	San Joaquin Rtd	John Coose	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Transportation Agencies	Sonoma Marin Area Rail Transit	Marc Bader	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Transportation Agencies	Sonoma Marin Area Rail Transit	Doug Beck	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
Transportation Agencies	Sonoma Marin Area Rail Transit	Jennifer Mcgill	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Tribe	Amah Mutsun Tribal Band	Valentin Lopez, Chairman	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Tribe	American Indian Council of Mariposa County (Southern Sierra Miwuk Nation)	Sandra Vasquez, Tribal Chair	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Tribe	Bear River Band of Rohnerville Rancheria	Josefina Cortez, Tribal Chairwoman	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)
Tribe	Berry Creek Rancheria	Jennifer Santos, Tribal Administrator	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)
Tribe	Big Lagoon Rancheria	Virgil Moorehead, Chairperson	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
Tribe	Big Sandy Rancheria	Elizabeth Kipp, Chairperson	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)
Tribe	Big Valley Band of Pomo Indians	Veronica Aparicio, Executive Assistant	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)
Tribe	Blue Lake Rancheria	Anita Huff, OES Director	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)
Tribe	Buena Vista Rancheria of Me-Wuk Indians	Michael DeSpain, Chief Operations Officer	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)
Tribe	Butte Tribal Council	Ren Reynolds, General	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
Tribe	California Choinumni Tribal Project	Rosemary Smith, Tribal Chair	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Tribe	California Valley Miwok Tribe	Sylvia Burley, Chairperson	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)
Tribe	Chaushila Yokuts	Jerry Brown, Chairman	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Tribe	Cher-Ae Heights Indian Community of the Trinidad Rancheria	Jaque Hostler-Carmesin, Chief Executive Officer	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)
Tribe	Chicken Ranch Rancheria	LeeAnn Hatton, Assistant Tribal Administrator	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)
Tribe	Cloverdale Rancheria	Maria Elliott, Tribal Secretary	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23)

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
						Table-Top Exercise (6/6/23)
Tribe	Coastal Band of the Chumash Nation	Mia Lopez, Chairperson	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Tribe	Coastanoan Oholone Rumsen-Mutsen Tribe	Patrick Orozco, General	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Tribe	Cold Springs Rancheria of Mono Indians	Helena Alarcon, Chairwoman	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)
Tribe	Cortina Rancheria	Charlie Wright, Chairperson	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)
Tribe	Coyote Valley Band of Pomo Indians	Michael Hunter, Council Chairman	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
Tribe	Dry Creek Rancheria Band of Pomo Indians	Matt Epstein, Fire Chief	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)
Tribe	Dumna Wo-Wah Tribal Government	Robert Ledger, Chairperson	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Tribe	Dunlap Band of Mono Indians	Florence Dick, Tribal Secretary	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Tribe	Dunlap Band of Mono Indians Historical Preservation Society	Mandy Marine, President	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Tribe	Elem Indian Colony	Agustin Garcia, Chairman	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)
Tribe	Enterprise Rancheria of Maidu Indians	Tony Whiddon, Casino Director of Security	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
Tribe	Federated Indians of Graton Rancheria	Greg Sarris, Chairman	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)
Tribe	Greenville Rancheria	Ntango (Desi) Banani, Medical Director	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)
Tribe	Grindstone Rancheria	Ronald Kirk, Chairman	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)
Tribe	Guidiville Rancheria	Meyo Marrufo, EPA Director	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)
Tribe	Habematolel Pomo of Upper Lake	Anthony Arroyo, Chairperson	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
Tribe	Haslett Basin Traditional Committee	Martin Davis, Chairman	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Tribe	Honey Lake Maidu	Ronald Morales, General	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Tribe	Hoopa Valley Tribe	Joe Davis, Chairman	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)
Tribe	Hopland Reservation	Sonny Elliott, Chairperson	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)
Tribe	Indian Canyon Mutsun Band of Costanoan	Ann Marie Sayers, Chairperson	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Tribe	Ione Band of Miwok Indians	Sara Dutschke Setshwaelo, Chairperson	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
Tribe	Jackson Rancheria	Larry Forst, Facilities Director	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)
Tribe	Karuk Tribe	Jacqueline Nushi, Emergency Manager	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)
Tribe	Kawaiisu Tribe	David Robinson, Chairperson	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Tribe	Kern Valley Indian Council	Robert Robinson, Historic Preservation Officer	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Tribe	Laytonville Rancheria	Fred Simmons, EPA Tech	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)
Tribe	Lower Lake Rancheria	Darin Beltran, Chairman	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23)

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
						Table-Top Exercise (6/6/23)
Tribe	Lytton Rancheria	Lisa Miller, Tribal Administrator	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)
Tribe	Manchester-Point Arena Rancheria	Linda Lawson, Tribal Council	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)
Tribe	Mechoopda Indian Tribe	Mark Alabanza, Tribal Administrative Officer	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)
Tribe	Middletown Rancheria	Jose Simon, Chairman	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)
Tribe	Mishewal-Wappo of Alexander Valley	Scott Gabaldon, Chairperson	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
Tribe	Mooretown Rancheria	Ronald Butz, Tribal Ops	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)
Tribe	Muwekma Ohlone Indian Tribe	Monica Arellano, Vice Chairwoman	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Tribe	Nor-Rel-Muk Nation	Marilyn Delgado, Chairperson	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Tribe	North Fork Rancheria	Maryann McGovran, Treasurer	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)
Tribe	Northern Band of Mono Yokuts	Delaine Bill, Chairman	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Tribe	Noyo River Indian Community	Tribal Administration, General	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Tribe	Ohlone Indian Tribe	Andrew Galvan, General	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
Tribe	Paskenta Rancheria	Mike Foss, Security Manager	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)
Tribe	Picayune Rancheria (Chukchansi Tribe)	John Saucedo, Cultural Resource Monitor	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)
Tribe	Pinoleville Reservation	Leona Williams, Chairperson	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)
Tribe	Pit River Tribes	Agnes Gonzalez, Chairwoman	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)
Tribe	Potter Valley Tribe	Salvador Rosales, Tribal Chairman	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
Tribe	Redding Rancheria	Carlos Wilson , Maintenance Supervisor	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)
Tribe	Redwood Valley Rancheria	Mary Camp, Tribal Administrator	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)
Tribe	Robinson Rancheria	Esther Stauffer, Tribal Administrator	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)
Tribe	Round Valley Reservation	Michael Henry, Chief of Police	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)
Tribe	Salinan Tribe of Monterey, San Luis Obispo and San Benito Counties	John Burch, Chairperson	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY
(CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
Tribe	San Luis Obispo County Chumash Council	Mark Vigil, Chairperson	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Tribe	Santa Rosa Rancheria	Rueben Barrios, Chairperson	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)
Tribe	Santa Ynez Band of Chumash Indians	Daune Dowell, Risk Manager	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)
Tribe	Scotts Valley Band of Pomo Indians	Sorhna Li, CFO/Interim TANF ED	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)
Tribe	Shebelna Band of Mendocino Coast Pomo Indians	Shirley Harbor, Chairperson	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Tribe	Sherwood Valley Band of Pomo Indians	Melanie Rafnan, Tribal Chairperson,	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23)

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
						Table-Top Exercise (6/6/23)
Tribe	Shingle Springs Rancheria	Regina Cuellar, Chairwoman	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)
Tribe	Sierra Mono Museum	Stephanie Clark, Director	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Tribe	Stewarts Point Rancheria (Kashaya Pomo)	Enrique Sanchez, Emergency Planner	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)
Tribe	Strawberry Valley Rancheria	Cathy Bishop, Chairperson	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Tribe	Susanville Indian Rancheria	Arian Hart, Tribal Chairman	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)
Tribe	Table Mountain Rancheria	Leanne Walker-Grant, Chairperson	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise	Functional Exercise (3/27/23 to

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
					(6/13/22 to 6/17/22)	3/31/23) Table-Top Exercise (6/6/23)
Tribe	Tejon Indian Tribe	Octavio Eschobebo, Chairperson	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)
Tribe	Traditional Choinumni Tribe (East of Kings River)	David Alvarez, Chairman	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Tribe	Trina Marine Ruano Family	Ramona Garibay, Representative	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Tribe	Tsungwe Council	James Ammon, Chairman	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Tribe	Tubatulabal Tribe	Robert Gomez, Chairman	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Tribe	Tule River Indian Tribe	Joe Boy Perez, Director of Emergency Management	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
Tribe	Tuolumne Band of Me-Wuk Indians	Andrea Reich, Chairwoman	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)
Tribe	United Auburn Indian Community	Brian Guth, Interim Tribal Administrator	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)
Tribe	Wailaki Tribe	Louis Hoaglin, Chairperson	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Tribe	Washoe Tribe	Serrell Smokey, Chairperson	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)
Tribe	Wilton Rancheria	Jesus Tarango Jr, Chairman	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
Tribe	Winnemem Wintu Tribe	Caleen Sisk, Spiritual Leader	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Tribe	Wintu Tribe of Northern California	Wade McMaster, Chairman	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Tribe	Wiyot Tribe	Theodore Hernandez, Tribal Chairman	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)
Tribe	Wukchumni Tribal Council	Darlene Franco, Chairperson	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Tribe	Wuksachi Indian Tribe	Kenneth Woodrow, Chairman	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Tribe	Xolon Salinan Tribe	Johnny Eddy, Chairperson	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Tribe	Yocha Dehe Wintun Nation	Becky Ramirez, Fire Chief	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
Tribe	Yurok Tribe	Amos Pole, Deputy OES Director	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)
Water Agencies	Alleghany Water District	Rae Arbogast	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Water Agencies	Alleghany Water District	Bruce Coons	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Water Agencies	Amador Water Agency	Joel Mottishaw	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Water Agencies	Amador Water Agency	Kreg Miller	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Water Agencies	Amador Water Agency	Rick Ferriera	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Water Agencies	American Water Works Company Inc	Christina Baril	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Water Agencies	American Water Works Company Inc	Margaret Digenova	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
Water Agencies	Army Corp Of Engineers	Poppy Lozoff	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Water Agencies	Aromas Water District	David Dealba	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Water Agencies	Aromas Water District	Shaun Smith	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Water Agencies	Aromas Water District	Robert Johnson	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Water Agencies	Bear Valley Water District	Jeff Gouveia	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Water Agencies	Bear Valley Water District	Judi Silber	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Water Agencies	Bodega Bay Public Utility District	Garett Watts	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Water Agencies	Bodega Bay Public Utility District	Janet Ames	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Water Agencies	Bodega Bay Public Utility District	Vickie Watts	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
Water Agencies	California American Water	Nina Miller	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Water Agencies	California American Water	Rick Saldivar	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Water Agencies	California Department Of Corrections	CCC Watch Commander	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Water Agencies	California Department Of Corrections	Mary Tilja	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Water Agencies	California Department Of Forestry	Deborah Lotten	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Water Agencies	California Department Of Forestry	Jeff Chandler	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Water Agencies	California Department Of Forestry	P.e. Michael Duggan	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Water Agencies	California Department Of Water Resources	Delta Field Division Area Control Center	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
Water Agencies	California Department Of Water Resources	New 2021 PSPS Notification Dist List Psps	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)
Water Agencies	California Department Of Water Resources	Octavio Herrera	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)
Water Agencies	California Water Service Company	Mike Utz	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Water Agencies	California Water Service Company	Cal Water PSPS Notice Mailbox	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Water Agencies	California Water Service Company	Greg Silva	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Water Agencies	California Water Service Company	Rosana Marino	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Water Agencies	California Water Service Company	Steve Cavallini	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY
(CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
Water Agencies	Cambria Community Services District	John Weigold	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Water Agencies	Cambria Community Services District	John Allchin	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Water Agencies	Cambria Community Services District	Ray Dienzo	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Water Agencies	Central Coast Water Authority	John Brady	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Water Agencies	Central Coast Water Authority	Todd York	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Water Agencies	Central Contra Costa Sanitary District	Leo Gonzalez	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Water Agencies	Central Contra Costa Sanitary District	Alan Weer	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Water Agencies	Central Marin Sanitation Agency	Chris Finton	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Water Agencies	Central Marin Sanitation Agency	Jean Saint Louis	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
Water Agencies	Central Marin Sanitation Agency	Peter Kistenmacher	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Water Agencies	Chicken Ranch Rancheria	Mike Smith	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Water Agencies	City And County Of San Francisco	Andrew Clark	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Water Agencies	City And County Of San Francisco	Emrulkayes Akter	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Water Agencies	City And County Of San Francisco	John O’Connell	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Water Agencies	City And County Of San Francisco	James Spark	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Water Agencies	City And County Of San Francisco	Stephen Fong	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Water Agencies	City Of Oakland Public Works	Derin Minor	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Water Agencies	City Of Oakland Public Works	Joe Devries	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
Water Agencies	City Of Oakland Public Works	Marco Torres	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Water Agencies	Contra Costa Water District	James Larot	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Water Agencies	Contra Costa Water District	Joe Piro	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Water Agencies	Contra Costa Water District	CCWD Control Room	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Water Agencies	CPPA CCWD Water Treatment	Damon Wyckoff	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Water Agencies	CPPA CCWD Water Treatment	Jesse Hampton	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Water Agencies	CPPA CCWD Water Treatment	Pat Burkhardt	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Water Agencies	Cuyama Community Service District	Vivian Vickery	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Water Agencies	Delta Diablo	Joaquin Gonzalez	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
Water Agencies	Dept Of The Army	Robert Sanders	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Water Agencies	Downieville Public Utilities District	Paul Douville	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Water Agencies	Downieville Public Utilities District	Richard Melim	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Water Agencies	Dublin San Ramon Services District	Jeff Carson	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Water Agencies	Dublin San Ramon Services District	Virgil Sevilla	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Water Agencies	East Bay Municipal Utility District	Bill Pulsifer	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Water Agencies	East Bay Municipal Utility District	Brett Kawakami	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Water Agencies	East Bay Municipal Utility District	Damon Hom	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Water Agencies	East Bay Municipal Utility District	Glenn Dombeck	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

**TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY
(CONTINUED)**

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
Water Agencies	East Bay Municipal Utility District	Ike Bell	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Water Agencies	East Bay Municipal Utility District	EBM Operations Control Center	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Water Agencies	East Bay Municipal Utility District	Pardee Area Control Center	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Water Agencies	East Bay Municipal Utility District	Robert Mac	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Water Agencies	East Bay Municipal Utility District	Wastewater Control Room	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Water Agencies	El Dorado Irrigation District	Bill Petterson	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Water Agencies	El Dorado Irrigation District	Cody Smith	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Water Agencies	El Dorado Irrigation District	John Chavers	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Water Agencies	El Dorado Irrigation District	Kurt Mikkola	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
Water Agencies	El Dorado Irrigation District	Ron Barney	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Water Agencies	El Dorado Irrigation District	Radenko Odzakovic	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Water Agencies	El Dorado Irrigation District	Tracy Crane	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Water Agencies	Fall River Mills Community Service District	Bill Rodeski	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Water Agencies	Fall River Mills Community Service District	Cecil Ray	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Water Agencies	Fall River Mills Community Service District	Joe Huston	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Water Agencies	First Mace Meadow Water Assn Inc	Neil Thompson	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Water Agencies	Haskell Creek Tract Association	Malcolm Myles	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Water Agencies	Laguna County Sanitation District	Kelly Hubbard- PSPS Contact Only	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY
(CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
Water Agencies	Laguna County Sanitation District	PSPS Email Only	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Water Agencies	Laguna County Sanitation District	Scott Hosking	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Water Agencies	Lake Don Pedro Community Service District	Patrick Mcgowan	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Water Agencies	Lake Don Pedro Community Service District	Randy Gilgo	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Water Agencies	Lebec County Water District	Daniel Garcia	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Water Agencies	Lebec County Water District	Jessica Carroll	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Water Agencies	Leland Meadows Water	Lance Vetesy	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Water Agencies	Marin Municipal Water District	Erik Westerman	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Water Agencies	Marin Municipal Water District	Gary Andersen	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY
(CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
Water Agencies	Marin Municipal Water District	Mmwd Operations	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Water Agencies	Mi Wuk Village Mut Water Co	Kevin Lancaster	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Water Agencies	Mi Wuk Village Mut Water Co	Linda Logan	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Water Agencies	Mineral Mtn Ests	Rick Lazzeri	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Water Agencies	Mission Hills Community Services District	Javier Rodriguez	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Water Agencies	Modesto Irrigation District	MID Control Room	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Water Agencies	Murphys Sanitary Dist	Dan Murphy	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Water Agencies	Napa Sanitation District	Gabe Snook	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Water Agencies	Napa Sanitation District	James Keller	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
Water Agencies	Napa Sanitation District	Mark Egan	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Water Agencies	Nipomo Community Services District	Francisco Maldonado	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Water Agencies	Nipomo Community Services District	Peter Sevcik	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Water Agencies	Novato Sanitary District	Jeff Andress	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Water Agencies	Novato Sanitary District	Jeff Boheim	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Water Agencies	Novato Sanitary District	John Bailey	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Water Agencies	Novato Sanitary District	John O'hare	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Water Agencies	Oakdale Irrigation District	Aj Borba	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Water Agencies	Oakdale Irrigation District	Eric Thorburn	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY
(CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
Water Agencies	Oakdale Irrigation District	OID Emergency Phone	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Water Agencies	Oaks Mobile Home Homeowners Association	Elizabeth E	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Water Agencies	Placer County Water Agency	Andy Hamilton	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Water Agencies	Placer County Water Agency	Julie Hamilton	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Water Agencies	Placer County Water Agency	Jeremy Shepard	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Water Agencies	Placer County Water Agency	Ken Yunk	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Water Agencies	Placer County Water Agency	Lance Hartung	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Water Agencies	Port Of Redwood City	Michael Patolo	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
Water Agencies	Port Of Redwood City	Robin Kim	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Water Agencies	Port Of Redwood City	Robert Peter	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Water Agencies	River Pines Public Utility District	Candie Bingham	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Water Agencies	San Andreas Land Disposal System	On Call Operator Rotation	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Water Agencies	San Jose Water Company	Colby Sneed	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Water Agencies	San Jose Water Company	Curt Rayer	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Water Agencies	San Jose Water Company	Supervisor On Call	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Water Agencies	San Lorenzo Valley Water District	James Furtado	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Water Agencies	San Lorenzo Valley Water District	Rick Rogers	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY
(CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
Water Agencies	San Rafael Sanitation District	Bill Guerin	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Water Agencies	San Rafael Sanitation District	Darin White	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Water Agencies	San Rafael Sanitation District	Quinn Gardner	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Water Agencies	Sausalito Marin City Sanitary District	Cathy Bondanza,	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Water Agencies	Sausalito Marin City Sanitary District	Primary On-call	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Water Agencies	Sausalito Marin City Sanitary District	Kevin Rahman	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Water Agencies	Scotts Valley Water District	David Mcnair	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Water Agencies	Scotts Valley Water District	Ryan Ritchie	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Water Agencies	Sewer Agency Of Southern Marin	Mark Grushayev	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
Water Agencies	Sewer Agency Of Southern Marin	Mark Wilson	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Water Agencies	Sewer Agency Of Southern Marin	Roger Paskett	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Water Agencies	Sonoma County Water Agency	Operator Desk 24/7	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Water Agencies	Sonoma County Water Agency	Steve Girard	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Water Agencies	Soquel Creek Water District	David Patten	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Water Agencies	Soquel Creek Water District	Nick Emmert	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Water Agencies	Stockton East Water District	Chris Donis	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Water Agencies	Stockton East Water District	David Higares	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Water Agencies	Stockton East Water District	Jim Wunderlich	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY
(CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
Water Agencies	Tiburon Sanitary District	Dan Latorre	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Water Agencies	Tiburon Sanitary District	KC Cottrell	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Water Agencies	Tiburon Sanitary District	Tony Rubio	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Water Agencies	Tuolumne Utilities District	Eric Hall	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Water Agencies	Tuolumne Utilities District	Emily Long	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Water Agencies	US Army Corps Of Engineers	Calvin Foster	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Water Agencies	US Army Corps Of Engineers	Jay Tulley	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Water Agencies	US Army Corps Of Engineers	Tom Ehrke	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Water Agencies	Valley Springs Public Utility District	Sarah Pflug	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
Water Agencies	Vandenberg Village Csd	Joe Barget	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Water Agencies	Vandenberg Village Csd	Mike Garner	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Water Agencies	Washington County Water District	Washington County Water District Main Number	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Water Agencies	Yocha Dehe Wintun Nation	Andy Gardner	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Water Agencies	Yocha Dehe Wintun Nation	Jim Etters	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Water Agencies	Yocha Dehe Wintun Nation	Matt Schneider	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Water Agencies	Yosemite Springs Park Utility Company Inc	Ken Harrington	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Water Agencies	Yosemite Springs Park Utility Company Inc	Jonathan Penrose	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Water Agencies	Yosemite Springs Park Utility Company Inc	Jason Teeter	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A

TABLE 8-46:
HIGH-LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY (CONTINUED)

Public Safety Partner Group	Name of Entity	Point of Contact and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed*	Communication Exercise(s): Date of Planned Next
Water Agencies	Zone 7 Alameda County Flood Control Dist	PSPS Distribution List	See 8.4.3.2 narrative for key protocols.	Annually	N/A	N/A
Publicly-Owned Utilities	Northern California Power Agency	Michael Brush	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)
Publicly-Owned Utilities	Northern California Power Agency	Anish Nand	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)
Publicly-Owned Utilities	Southern California Edison	Tom Brady	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)
Publicly-Owned Utilities	Southern California Edison	Marco Aceituno-Murillo	See 8.4.3.2 narrative for key protocols.	Annually	Full-Scale Exercise (6/13/22 to 6/17/22)	Functional Exercise (3/27/23 to 3/31/23) Table-Top Exercise (6/6/23)

Appendix F.3.2 – 8.5 Community Outreach and Engagement

The electrical corporation must provide all detailed documentation from Section 8.5 in this appendix.

TABLE 8-59:
PG&E'S LIST OF COMMUNITY PARTNERS

Community Partners	County	City
California Foundation for Independent Living Centers (CFILC)	All	All
Regional Centers	All	All
In-Home Support Services (IHSS)	All	All
California Network of 211	All	All
Alameda County Community Food Bank	Alameda	All cities in Alameda County
Amador Tuolumne Community Action Agency	Amador, Tuolumne	All cities in Amador and Tuolumne counties
Clear Lake Gleamers Food Bank	Lake	All cities in Lake County
Central California Food Banks	Fresno, Kings, Tulare	All cities in Fresno, Kings, and Tulare counties
Community Action Agency of Butte County	Butte, Colusa, Glenn, Plumas, Sierra, Tehama	All cities in Butte, Colusa, Glenn, Plumas, Sierra, and Tehama counties
Community Action of Napa Valley Food Bank	Napa	All cities in Napa County
Dignity Health Connected Living	Shasta	All cities in Shasta County
El Dorado Food Bank	Alpine, El Dorado	All cities in Alpine and El Dorado counties
Food For People	Humboldt	All cities in Humboldt County
Food Bank of Contra Costa & Solano	Contra Costa, Solano	All cities in Contra Costa and Solano counties
Food Bank of Nevada County	Nevada	All cities in Nevada County
Placer Food Bank	El Dorado, Nevada, Placer	All cities in El Dorado, Nevada, and Placer counties
Redwood Empire Food Bank	Humboldt, Lake, Sonoma	All cities in Humboldt, Lake, Sonoma
Second Harvest Food Bank of Silicon Valley	San Mateo, Santa Clara	All cities in San Mateo and Santa Clara counties
Second Harvest Food Bank of San Joaquin and Stanislaus	San Joaquin, Stanislaus	All cities in San Joaquin and Stanislaus counties

TABLE 8-59:
PG&E'S LIST OF COMMUNITY PARTNERS
(CONTINUED)

Community Partners	County	City
Second Harvest Food Bank of Santa Cruz	Santa Cruz	All cities in Santa Cruz County
The Resource Connection	Calaveras	All cities in Calaveras County
The San Francisco Food Bank	Marin, San Francisco	All cities in Marin and San Francisco counties
Yolo Food Bank	Yolo	All cities in Yolo County
Yuba Sutter Food Bank	Sutter, Yuba	All cities in Sutter, Yuba
Redirect Nuevo Camino	Placer, Sacramento	All cities in Placer and Sacramento counties
Chico Meals on Wheels	Butte	Portions of Butte County
Clearlake Senior Center	Lake	Portions of Lake County
Coastal Seniors	Mendocino, Sonoma	Portions of Mendocino, Sonoma counties
Common Ground Senior Services	Amador, Calaveras	Portions of Amador and Calaveras counties
Community Bridges	Santa Cruz	Portions of Santa Cruz County
Council on Aging, Sonoma County	Marin, Sonoma	Portions of Marin and Sonoma counties
Gold Country Community Services	Nevada	Portions of Nevada County
J-Sei	Alameda, Contra Costa	Portions of Alameda, Contra Costa counties
Lakeport Senior Center	Lake	Portions of Lake County
Life Elder Care	Alameda	Portions of Alameda County
Live Oak Senior Center	Alameda	Portions of Alameda County
Meals on Wheels Diablo Region	Contra Costa	Portions of Contra Costa County
Meals on Wheels Monterey Peninsula	Monterey	Portions of Monterey County
Meals on Wheels Solano County	Solano	Portions of Solano County
Middletown Senior Center	Lake	Portions of Lake County
Passages	Butte	Portions of Butte County

TABLE 8-59:
PG&E'S LIST OF COMMUNITY PARTNERS
(CONTINUED)

Community Partners	County	City
Peninsula Volunteers	San Mateo	Portions of San Mateo County
Petaluma People Services	Sonoma	Portions of Sonoma County
Senior Coastsiders	San Mateo	Portions of San Mateo County
Service Opportunity for Seniors	Alameda	Portions of Alameda County
Spectrum Community Services	Alameda	Portions of Alameda County
West Contra Costa Meals on Wheels	Contra Costa	Portions of Contra Costa County
Area Agency on Aging, Area 4	Sutter, Yuba	Portions of Sutter and Yuba counties
Cope Family Center	Napa	All cities in Napa County
Food For Thought	Sonoma	Portions of Sonoma County
Open Heart Kitchen	Alameda	Portions of Alameda County
California Council of the Blind	All	All
Lost Sierra Food Project	Plumas	Portions of Plumas County
Haven of Hope on Wheels	Butte	Portions of Butte County

TABLE 8-59:
PG&E'S LIST OF COMMUNITY PARTNERS
(CONTINUED)

Multicultural Media Partners	Language(s)	Coverage
Univision Sacramento	Spanish	Sacramento, San Joaquin, Stanislaus, Amador, Calaveras, El Dorado, Nevada, Placer, Plumas, Sierra, Solano, Sutter, Tuolumne, Yolo, Yuba
Univision Fresno	Spanish	Mariposa, Merced, Madera, Fresno, Kings, Tulare
Univision Bay Area	Spanish	Alameda, Contra Costa, Lake, Marin, Mendocino, Napa, San Francisco, San Mateo, Santa Clara, Solano, Sonoma
Telemundo Sacramento	Spanish	Plumas, Colusa, Yolo, Solano, San Juaquin, Stanislaus, Tuolumne, Calaveras, Sacramento, Sutter, Yuba, Nevada, Placer, El Dorado, Amador
Telemundo Fresno	Spanish	Fresno, Madera, Kings, Tulare, Merced, Mariposa
Telemundo Bay Area	Spanish	San Francisco, Contra Costa, Santa Clara, Marin, Alameda, San Mateo, Sonoma, Napa, Solano, Mendocino, Lake
Radio Lazer Sacramento	Spanish	Fresno, Stanislaus, Sacramento, Yolo, Salinas-Monterrey, Santa Rosa-Sonoma, Ventura, Santa Clara & Kern
Radio Lazer Bay Area	Spanish	Santa Clara, Santa Cruz, San Mateo, Alameda, San Mateo, San Francisco, Marin, Sonoma, Napa, Contra Costa and Solano
Lotus Radio Fresno	Spanish	Fresno, Madera, Kings, Tulare, Merced, Mariposa
Lotus Radio Bakersfield	Spanish	Kern
Lotus Radio Sacramento	Spanish	Sacramento, San Joaquin, Contra Costa, Solano, Napa, Yolo, Colusa, Sutter, Yuba, Butte, Nevada, Placer, El Dorado, Amador, Calaveras

TABLE 8-59:
PG&E'S LIST OF COMMUNITY PARTNERS
(CONTINUED)

Multicultural Media Partners	Language(s)	Coverage
Radio Bilingue	Spanish/Mixteco	Kern, Tulare, Kings, Fresno, Madera, Merced, Stanislaus, San Joaquin, Monterey, San Luis Obispo, Mendocino, Santa Barbara (Santa Maria), Santa Cruz (Watsonville)
KBBF Radio	Spanish/Mixteco	Napa, Sonoma, and Mendocino counties, as well as many of the cities in the San Francisco Bay area and approaching Sacramento
D'Primeramano	Spanish	Sacramento, Yolo and San Joaquin
El Popular News	Spanish	Kern
Wine Country Radio	Spanish	Napa, Lake, and Sonoma
Alianza News	Spanish	Santa Clara, San Francisco, and Alameda counties. Online version covers entire state of California.
Sports Media Radio	Spanish	Santa Clara, San Francisco, Contra Costa
Fusion Latina Network	Spanish	Alameda, Contra Costa, Solano
Radio Campesina	Spanish	Fresno, Santa Barbara, San Luis Obispo, Monterey, San Benito, and Santa Cruz
Skylink TV	Chinese (Mandarin and Cantonese)	Alameda, Contra Costa, Lake, Marin, Mendocino, Napa, San Francisco, San Mateo, Santa Clara, Solano, Sonoma

**TABLE 8-59:
PG&E'S LIST OF COMMUNITY PARTNERS
(CONTINUED)**

Multicultural Media Partners	Language(s)	Coverage
Sing Tao Chinese Radio	Chinese (Mandarin and Cantonese)	San Francisco, San Mateo, Alameda, Santa Clara, Contra Costa, Marin, Napa, Sonoma, Solano, Sacramento
News for Chinese Radio	Mandarin	San Francisco, San Mateo, Alameda, Santa Clara, Contra Costa, Marin, Napa, Sonoma, Solano
Sound of Hope Radio Network	Chinese (Mandarin and Cantonese)	San Francisco, San Mateo, Santa Clara, Alameda, Contra Costa, Solano and Marin
KTSF-TV	Chinese (Mandarin and Cantonese), Tagalog and Vietnamese	San Francisco, San Mateo, Santa Clara, Alameda, Contra Costa, Solano and Marin
KBIF Radio	Hmong and Punjabi	Fresno, Madera, Tulare, Kern, San Joaquin, Merced counties, Sacramento
Hmong TV Network	Hmong	Fresno, Madera, Merced, Mariposa and Tulare
Crossings TV	Mandarin, Cantonese, Tagalog, Vietnamese, Japanese, Punjabi, Hmong and Korean	Entire CA via Comcast Xfinity
KSJZ-Korean American Radio	Korean	All the way up to Santa Rosa, San Francisco, Oakland, Alameda, Santa Clara, San Jose, Gilroy and all the way down to Santa Cruz/Monterey/ Carmel.
Saigon Radio	Vietnamese	Santa Clara County
KLBS Portuguese Radio	Portuguese	Entire CA via radio app
PAMA One Radio	Portuguese	Bay Area as Far East as Sonora, and from Sacramento to Tulare
Ethno FM	Russian	Sacramento, Placer, Yolo

TABLE 8-59:
PG&E'S LIST OF COMMUNITY PARTNERS
(CONTINUED)

Multicultural Media Partners	Language(s)	Coverage
KIRN Radio	Farsi	Kern
ONME Network	English (Black Community)	Fresno, Madera, Tulare, Mariposa, Merced, Kings, Stanislaus
Sac Cultural Hub	English (Black Community)	Sacramento

TABLE 8-61:
COLLABORATION IN LOCAL WILDFIRE MITIGATION PLANNING

Name of County, City, or Tribal Agency or Civil Society Organization (e.g., Non-Government Organization, Fire Safe Council	Program, Plan, or Document	Last Version of Collaboration	Level of Collaboration
Alameda County Fire Department	AB56	1/19/2022	Meeting
Alameda County Fire Department	AB56	1/26/2022	Meeting
Alameda County Fire Department	FRW/FLAG Training	3/23/2022	Meeting
Alameda County Fire Department	FRW/FLAG Training	6/22/2022	Meeting
Alameda County Office of Education	Emergency Management	10/27/2022	Meeting
Alameda County Social Services Department	AB56	1/19/2022	Meeting
Alameda County Social Services Department	AB56	1/26/2022	Meeting
Alameda County Social Services Department	Emergency Management	10/27/2022	Meeting
Alameda County Social Services Department	Emergency Management	10/27/2022	Meeting
Alameda County Social Services Department	FRW/FLAG Training	3/23/2022	Meeting
Albany Fire Department	AB56	1/19/2022	Meeting
Altaville-Melones Fire Protection District	AB56	4/13/2022	Meeting
Amador County Fire Protection District	AB56	5/5/2022	Presentation
Amador County Sheriff’s Department	AB56	5/5/2022	Presentation
American Canyon Fire Protection District	AB56	3/25/2022	Meeting
American Medical Response – San Mateo County	AB56	1/20/2022	Presentation
American Medical Response – San Mateo County	AB56	2/2/2022	Presentation
American Red Cross – Central California	Fire Season Coordination	4/21/2022	Meeting
American Red Cross – Northern California Coastal Region	Emergency Management	10/27/2022	Meeting
American Red Cross – Peninsula	Wildfire Safety	1/27/2022	Meeting

**TABLE 8-61:
COLLABORATION IN LOCAL WILDFIRE MITIGATION PLANNING
(CONTINUED)**

Name of County, City, or Tribal Agency or Civil Society Organization (e.g., Non-Government Organization, Fire Safe Council	Program, Plan, or Document	Last Version of Collaboration	Level of Collaboration
American Red Cross – Silicon Valley Chapter	Wildfire Safety	4/14/2022	Meeting
Anderson Fire Protection District	AB56	2/24/2022	Meeting
Anderson Fire Protection District	AB56	2/24/2022	Meeting
Anderson Valley Fire Protection District	AB56	4/6/2022	Meeting
Angels Camp Fire Department	AB56	4/13/2022	Meeting
Apple Valley Fire Protection District	AB56	3/24/2022	Meeting
Arbuckle – College City Fire Protection District	AB56	4/18/2022	Meeting
Arcata Fire Protection District	AB56	3/23/2022	Meeting
Artois Fire Protection District	AB56	2/9/2022	Meeting
Artois Fire Protection District	AB56	2/9/2022	Meeting
Auburn City Fire Department	AB56	1/27/2022	Meeting
Auburn City Fire Department	Wildfire Safety	3/31/2022	Meeting
Barstow Fire Protection District – City of Barstow Fire Department	AB56	4/19/2022	Meeting
Barstow Fire Protection District – City of Barstow Fire Department	Wildfire Safety	9/21/2022	Meeting
Bayliss Fire Protection District	AB56	2/9/2022	Meeting
Beale Air Force Base Fire Emergency Services	AB56	4/15/2022	Meeting
Benicia Fire Department	AB56	1/6/2022	Meeting
Benicia Fire Department	AB56	4/26/2022	Meeting
Berkeley Fire Department	AB56	1/19/2022	Meeting
Berkeley Fire Department	AB56	1/26/2022	Meeting
Berkeley Fire Department	Wildfire Safety	11/16/2022	Meeting
Berkeley Fire Department	FRW/FLAG Training	3/23/2022	Meeting

TABLE 8-61:
COLLABORATION IN LOCAL WILDFIRE MITIGATION PLANNING
(CONTINUED)

Name of County, City, or Tribal Agency or Civil Society Organization (e.g., Non-Government Organization, Fire Safe Council	Program, Plan, or Document	Last Version of Collaboration	Level of Collaboration
Berkeley Fire Department	FRW/FLAG Training	6/22/2022	Meeting
Biggs City Fire Department	AB56	2/10/2022	Meeting
Blue Lake Fire Protection District	AB56	3/24/2022	Meeting
Blue Lake Rancheria Fire Department	AB56	4/13/2022	Meeting
Bridgeville Fire Protection District	AB56	3/23/2022	Meeting
Buckskin Fire District	Wildfire Safety	10/20/2022	Meeting
Burbank-Paradise Fire Protection District	AB56	5/5/2022	Meeting
Bureau of Land Management – Modoc	AB56	4/19/2022	Meeting
Bureau of Land Management – Hollister	AB56	3/25/2022	Meeting
Burney Fire Protection District	AB56	2/17/2022	Meeting
Butte City Fire Department	AB56	2/9/2022	Meeting
Butte County Office of Emergency Services	Mutual Aid	4/6/2022	Meeting
CADRE Collaborating Agencies' Disaster Relief Effort	Wildfire Safety	4/14/2022	Meeting
CAL FIRE – Amador-El Dorado	Wildfire Safety	1/19/2022	Meeting
CAL FIRE – Amador-El Dorado	AB56	3/22/2022	Presentation
CAL FIRE – Amador-El Dorado	Wildfire Safety	4/5/2022	Webinar
CAL FIRE – Amador-El Dorado	Wildfire Safety	5/17/2022	Meeting
CAL FIRE – Amador-El Dorado	AB56	5/5/2022	Presentation
CAL FIRE – Butte	AB56	2/10/2022	Meeting
CAL FIRE – Butte	Sierra Pacific Industries & Cal Fire Wildland Fire	5/6/2022	Meeting
CAL FIRE – Fresno-Kings	AB56	3/24/2022	Meeting
CAL FIRE – Fresno-Kings	Fire Season Coordination	4/21/2022	Meeting

TABLE 8-61:
COLLABORATION IN LOCAL WILDFIRE MITIGATION PLANNING
(CONTINUED)

Name of County, City, or Tribal Agency or Civil Society Organization (e.g., Non-Government Organization, Fire Safe Council	Program, Plan, or Document	Last Version of Collaboration	Level of Collaboration
CAL FIRE – Humboldt-Del Norte	AB56	3/23/2022	Meeting
CAL FIRE – Lassen-Modoc-Plumas	AB56	4/19/2022	Meeting
CAL FIRE – Lassen-Modoc-Plumas	Sierra Pacific Industries & Cal Fire Wildland Fire	5/6/2022	Meeting
CAL FIRE – Madera-Mariposa-Merced	AB56	4/28/2022	Meeting
CAL FIRE – Mendocino	AB56	3/23/2022	Meeting
CAL FIRE – Mendocino	FRW	3/23/2022	Meeting
CAL FIRE – Nevada-Yuba-Placer	AB56	1/27/2022	Meeting
CAL FIRE – Nevada-Yuba-Placer	Wildfire Safety	3/31/2022	Meeting
CAL FIRE – Nevada-Yuba-Placer	Nevada/Yuba/Placer Annual Incident Management Drill	5/24/2022	Training
CAL FIRE – San Benito-Monterey	AB56	3/9/2022	Meeting
CAL FIRE – San Bernardino	AB56	3/24/2022	Meeting
CAL FIRE – San Bernardino	Wildfire Safety	9/22/2022	Meeting
CAL FIRE – San Luis Obispo	AB56	2/3/2022	Meeting
CAL FIRE – San Mateo-Santa Cruz	AB56	1/20/2022	Presentation
CAL FIRE – San Mateo-Santa Cruz	TD-1464S Wildfire Prevention and Mitigation	10/19/2022	Prescribed Burn
CAL FIRE – San Mateo-Santa Cruz	TD-1464S Wildfire Prevention and Mitigation	10/26/2022	Meeting
CAL FIRE – San Mateo-Santa Cruz	TD-1464S Wildfire Prevention and Mitigation	10/4/2022	Prescribed Burn

TABLE 8-61:
COLLABORATION IN LOCAL WILDFIRE MITIGATION PLANNING
(CONTINUED)

Name of County, City, or Tribal Agency or Civil Society Organization (e.g., Non-Government Organization, Fire Safe Council	Program, Plan, or Document	Last Version of Collaboration	Level of Collaboration
CAL FIRE – San Mateo-Santa Cruz	TD-1464S Wildfire Prevention and Mitigation	11/8/2022	Meeting
CAL FIRE – San Mateo-Santa Cruz	AB56	2/2/2022	Presentation
CAL FIRE – San Mateo-Santa Cruz	Wildfire Safety	5/4/2022	Prescribed Burn
CAL FIRE – San Mateo-Santa Cruz	Wildfire Safety	9/7/2022	Presentation
CAL FIRE – Santa Clara	Wildfire Safety	1/20/2022	Meeting
CAL FIRE – Santa Clara	AB56	3/17/2022	Meeting
CAL FIRE – Santa Clara	AB56	3/2/2022	Meeting
CAL FIRE – Shasta-Trinity	AB56	2/17/2022	Meeting
CAL FIRE – Shasta-Trinity	Sierra Pacific Industries & Cal Fire Wildland Fire	5/6/2022	Meeting
CAL FIRE – Siskiyou	AB56	4/21/2022	Meeting
CAL FIRE – Siskiyou	Sierra Pacific Industries & Cal Fire Wildland Fire	5/6/2022	Meeting
CAL FIRE – Sonoma-Lake-Napa	AB56	3/23/2022	Meeting
CAL FIRE – Sonoma-Lake-Napa	AB56	4/26/2022	Meeting
CAL FIRE – State Headquarters	Wildfire Safety	11/16/2022	Meeting
CAL FIRE – Tehama-Glenn	AB56	2/9/2022	Meeting
CAL FIRE – Tehama-Glenn	Sierra Pacific Industries & Cal Fire Wildland Fire	5/6/2022	Meeting
CAL FIRE – Tulare	AB56	3/10/2022	Meeting
CAL FIRE – Tuolumne-Calaveras	Wildfire Safety	10/13/2022	Meeting
CAL FIRE – Tuolumne-Calaveras	AB56	4/13/2022	Meeting

TABLE 8-61:
COLLABORATION IN LOCAL WILDFIRE MITIGATION PLANNING
(CONTINUED)

Name of County, City, or Tribal Agency or Civil Society Organization (e.g., Non-Government Organization, Fire Safe Council	Program, Plan, or Document	Last Version of Collaboration	Level of Collaboration
CAL FIRE – Tuolumne-Calaveras	AB56	4/21/2022	Meeting
Cal Trans	Fire Season Coordination	4/21/2022	Meeting
Calaveras Consolidated Fire Protection District	AB56	4/13/2022	Meeting
California Department of Corrections and Rehabilitation – Folsom State Prison	AB56	5/10/2022	Email
California Department of Rehabilitation and Corrections – Medical Facility	AB56	4/26/2022	Meeting
California Emergency Services Association (CESA)	Wildfire Safety	2/8/2022	Meeting
California Foundation for Independent Living Centers	Wildfire Safety	6/9/2022	Meeting
California Governor’s Office of Emergency Services	Mutual Aid	4/6/2022	Meeting
California Highway Patrol – Barstow	Wildfire Safety	9/21/2022	Meeting
California Highway Patrol – Fresno	Fire Season Coordination	4/21/2022	Meeting
California Highway Patrol – Redwood City	TD-1464S Wildfire Prevention and Mitigation	10/4/2022	Prescribed Burn
California Highway Patrol – Stockton	AB56	5/4/2022	Meeting
California Office of Emergency Services – Region II Coastal Region	AB56	1/20/2022	Presentation
California Office of Emergency Services – Yolo County	Fire Season Coordination	4/21/2022	Meeting
California Office of Emergency Services Region 3 – Shasta	Mutual Aid	4/6/2022	Meeting
California Public Utilities Commission	Wildfire Safety	6/9/2022	Meeting

TABLE 8-61:
COLLABORATION IN LOCAL WILDFIRE MITIGATION PLANNING
(CONTINUED)

Name of County, City, or Tribal Agency or Civil Society Organization (e.g., Non-Government Organization, Fire Safe Council	Program, Plan, or Document	Last Version of Collaboration	Level of Collaboration
Calistoga Fire Department	AB56	3/23/2022	Meeting
Cameron Park Community Services District	AB56	3/22/2022	Meeting
Cameron Park Community Services District	Wildfire Safety	5/17/2022	Meeting
Camp Roberts Fire Department	AB56	3/25/2022	Meeting
Capay Fire Protection District	AB56	2/9/2022	Meeting
Capay Valley Fire Protection District	AB56	5/10/2022	Meeting
Carlotta Community Services District	AB56	4/6/2022	Meeting
Carmel Fire Department	AB56	1/10/2022	Meeting
Central Calaveras Fire Protection District	AB56	4/13/2022	Meeting
Central County Fire Department	AB56	1/20/2022	Presentation
Central County Fire Department	Wildfire Safety	1/27/2022	Meeting
Central County Fire Department	TD-1464S Wildfire Prevention and Mitigation	10/4/2022	Prescribed Burn
Central County Fire Department	AB56	2/2/2022	Presentation
Central County Fire Department	Wildfire Safety	2/22/2022	Meeting
Central County Fire Department	Wildfire Safety	9/7/2022	Presentation
Central Marin Fire Authority	AB56	3/14/2022	Meeting
Ceres Fire Department	AB56	5/5/2022	Meeting
Chevron Refinery Fire Department	AB56	3/9/2022	Meeting
Chico Fire Department	AB56	2/10/2022	Meeting
Chico Fire Department	Mutual Aid	4/6/2022	Meeting
Chowchilla Fire Department	AB56	5/6/2022	Phone Call
City of Alameda Fire Department	AB56	1/19/2022	Meeting

TABLE 8-61:
COLLABORATION IN LOCAL WILDFIRE MITIGATION PLANNING
(CONTINUED)

Name of County, City, or Tribal Agency or Civil Society Organization (e.g., Non-Government Organization, Fire Safe Council	Program, Plan, or Document	Last Version of Collaboration	Level of Collaboration
City of Alameda Fire Department	AB56	1/26/2022	Meeting
City of Burlingame Administrative Office	Wildfire Safety	2/22/2022	Meeting
City of Cupertino Administrative Office	Wildfire Safety	6/9/2022	Meeting
City of Gilroy Administrative Office	Wildfire Safety	4/14/2022	Meeting
City of Gilroy Administrative Office	Wildfire Safety	6/9/2022	Meeting
City of Milpitas Administrative Office	Wildfire Safety	6/9/2022	Meeting
City of Oakland Administrative Office	Wildfire Safety	6/27/2022	Meeting
City of Pacifica Administrative Office	Wildfire Safety	1/27/2022	Meeting
City of Redwood City Administrative Office	Wildfire Safety	3/17/2022	Presentation
City of San Jose Administrative Office	Wildfire Safety	6/9/2022	Meeting
City of San Leandro Administrative Office	Emergency Management	10/27/2022	Meeting
City of Woodside Administrative Office	Wildfire Safety	1/27/2022	Meeting
Clarksburg Fire Protection District	AB56	5/10/2022	Meeting
Clements Rural Fire Protection District	AB56	4/6/2022	Meeting
Clements Rural Fire Protection District	AB56	5/4/2022	Meeting
Cloverdale Fire Protection District	AB56	3/9/2022	Meeting
Clovis Fire Department	AB56	4/26/2022	Meeting
Coalinga Fire Department	AB56	4/4/2022	Meeting

TABLE 8-61:
COLLABORATION IN LOCAL WILDFIRE MITIGATION PLANNING
(CONTINUED)

Name of County, City, or Tribal Agency or Civil Society Organization (e.g., Non-Government Organization, Fire Safe Council	Program, Plan, or Document	Last Version of Collaboration	Level of Collaboration
Coastside Fire Protection District	AB56	1/20/2022	Presentation
Coastside Fire Protection District	Wildfire Safety	1/27/2022	Meeting
Coastside Fire Protection District	AB56	2/2/2022	Presentation
Collegeville Fire Protection District	AB56	6/27/2022	Meeting
Colma Fire Protection District	AB56	1/20/2022	Presentation
Colma Fire Protection District	AB56	2/2/2022	Presentation
Colma Fire Protection District	Wildfire Safety	9/7/2022	Presentation
Columbia Fire Protection District	Wildfire Safety	10/13/2022	Meeting
Colusa County Office of Emergency Services	Mutual Aid	4/6/2022	Meeting
Colusa Fire Department	AB56	4/26/2022	Meeting
Contra Costa County Fire Protection District	AB56	3/9/2022	Meeting
Copperopolis Fire Protection District	AB56	4/13/2022	Meeting
Cordelia Fire Protection District	AB56	1/6/2022	Meeting
Cordelia Fire Protection District	AB56	4/26/2022	Meeting
Cosumnes Community Services District	AB56	4/28/2022	Meeting
Cosumnes Community Services District	AB56	4/7/2022	Meeting
Cottonwood Fire Protection District	AB56	2/17/2022	Meeting
Courtland Fire Protection District	AB56	4/28/2022	Meeting
Crockett-Carquinez Fire Protection District	AB56	3/9/2022	Meeting
Cupertino CERT	Wildfire Safety	4/14/2022	Meeting
Davis Fire Department	AB56	5/10/2022	Meeting

TABLE 8-61:
COLLABORATION IN LOCAL WILDFIRE MITIGATION PLANNING
(CONTINUED)

Name of County, City, or Tribal Agency or Civil Society Organization (e.g., Non-Government Organization, Fire Safe Council	Program, Plan, or Document	Last Version of Collaboration	Level of Collaboration
Defense Logistics Agency Fire Department	AB56	5/23/2022	Meeting
Denair Fire Protection District	AB56	5/5/2022	Meeting
Diamond Springs El Dorado Fire Protection District	Wildfire Safety	1/19/2022	Meeting
Diamond Springs El Dorado Fire Protection District	Wildfire Safety	4/5/2022	Webinar
Diamond Springs El Dorado Fire Protection District	Wildfire Safety	5/17/2022	Meeting
Dinuba Fire Department	AB56	3/10/2022	Meeting
Dixon Fire Department	AB56	1/6/2022	Meeting
Dixon Fire Department	AB56	4/26/2022	Meeting
Dunnigan Fire Protection District	AB56	5/10/2022	Meeting
East Bay Municipal Utility District (EBMUD)	Emergency Management	10/27/2022	Meeting
East Bay Regional Park District Fire Department	AB56	1/19/2022	Meeting
East Bay Regional Park District Fire Department	Wildfire Safety	11/16/2022	Meeting
East Contra Costa County Fire Protection District	AB56	3/9/2022	Meeting
East Palo Alto Police Department	Evacuation for Peninsula Bayside	1/13/2022	Meeting
East Palo Alto Police Department	Wildfire Safety	1/27/2022	Meeting
Ebbetts Pass Fire Department	AB56	4/13/2022	Meeting
El Cerrito Fire Department	AB56	3/9/2022	Meeting
El Dorado County Fire District	Wildfire Safety	1/19/2022	Meeting
El Dorado County Fire District	Wildfire Safety	4/5/2022	Webinar
El Dorado County Fire District	Wildfire Safety	5/17/2022	Meeting
El Dorado County Fire Safe Council	Wildfire Safety	4/5/2022	Webinar

TABLE 8-61:
COLLABORATION IN LOCAL WILDFIRE MITIGATION PLANNING
(CONTINUED)

Name of County, City, or Tribal Agency or Civil Society Organization (e.g., Non-Government Organization, Fire Safe Council	Program, Plan, or Document	Last Version of Collaboration	Level of Collaboration
El Dorado County Office of Emergency Services	Wildfire Safety	4/5/2022	Meeting
El Dorado County Office of Emergency Services	Wildfire Safety	4/5/2022	Webinar
El Dorado County Office of Emergency Services	Wildfire Safety	5/17/2022	Meeting
El Dorado County Sheriff’s Department	Wildfire Safety	4/5/2022	Meeting
El Dorado County Sheriff’s Department	Wildfire Safety	4/5/2022	Webinar
El Dorado Hills Fire Department	Wildfire Safety	1/19/2022	Meeting
El Dorado Hills Fire Department	AB56	3/29/2022	Meeting
El Dorado Hills Fire Department	Wildfire Safety	4/5/2022	Webinar
El Dorado Hills Fire Department	Wildfire Safety	5/17/2022	Meeting
El Dorado National Forest – Fire Department	Wildfire Safety	4/5/2022	Webinar
El Dorado National Forest – Fire Department	Wildfire Safety	5/17/2022	Meeting
Eldridge Fire Department	AB56	3/9/2022	Meeting
Elk Creek Fire Protection District	AB56	2/9/2022	Meeting
Elkhorn Fire Protection District	AB56	5/10/2022	Meeting
Escalon Fire Protection District	AB56	4/6/2022	Meeting
Esparto Fire Protection District	AB56	5/10/2022	Meeting
Fairfield Fire Department	AB56	1/6/2022	Meeting
Fairfield Fire Department	AB56	4/26/2022	Meeting
Fall River Valley Fire Protection District	AB56	3/15/2022	Meeting
Farmington	AB56	4/6/2022	Meeting
Federal Emergency Management Agency (FEMA) - National IMAT	Emergency Management	10/27/2022	Meeting
Fig Garden Fire District	AB56	3/24/2022	Meeting

TABLE 8-61:
COLLABORATION IN LOCAL WILDFIRE MITIGATION PLANNING
(CONTINUED)

Name of County, City, or Tribal Agency or Civil Society Organization (e.g., Non-Government Organization, Fire Safe Council	Program, Plan, or Document	Last Version of Collaboration	Level of Collaboration
Fire Safe San Mateo County	Wildfire Safety	1/12/2022	Meeting
Fire Safe San Mateo County	Wildfire Safety	2/9/2022	Meeting
Fire Safe San Mateo County	Wildfire Safety	3/9/2022	Meeting
Firebaugh Fire Department	AB56	4/5/2022	Meeting
Folsom Fire Department	AB56	4/7/2022	Meeting
Foresthill Fire Protection District	Wildfire Safety	3/31/2022	Meeting
Forestville Fire Protection District	AB56	3/9/2022	Meeting
Fort Mohave Mesa Fire Department	Wildfire Safety	10/20/2022	Meeting
Fortuna Fire Protection District	AB56	3/23/2022	Meeting
Fowler Fire Department	AB56	4/7/2022	Meeting
Fremont Fire Department	AB56	1/19/2022	Meeting
Fremont Fire Department	FRW/FLAG Training	3/23/2022	Meeting
French Camp-McKinley Rural Fire Protection District	AB56	4/6/2022	Meeting
French Camp-McKinley Rural Fire Protection District	AB56	5/4/2022	Meeting
Fresno County Fire Protection District	AB56	3/24/2022	Meeting
Fresno County Sheriff’s Department	Fire Season Coordination	4/21/2022	Meeting
Fresno Fire Department	AB56	3/24/2022	Meeting
Garden Valley Fire Protection District	Wildfire Safety	4/5/2022	Webinar
Garden Valley Fire Protection District	Wildfire Safety	5/17/2022	Meeting
Georgetown Fire Protection District	Wildfire Safety	1/19/2022	Meeting
Georgetown Fire Protection District	Wildfire Safety	4/5/2022	Webinar
Georgetown Fire Protection District	Wildfire Safety	5/17/2022	Meeting

TABLE 8-61:
COLLABORATION IN LOCAL WILDFIRE MITIGATION PLANNING
(CONTINUED)

Name of County, City, or Tribal Agency or Civil Society Organization (e.g., Non-Government Organization, Fire Safe Council	Program, Plan, or Document	Last Version of Collaboration	Level of Collaboration
Geyserville Fire Protection District	AB56	3/9/2022	Meeting
Gilroy Fire Department	AB56	3/2/2022	Meeting
Glenn - Codora Fire Protection District	AB56	2/9/2022	Meeting
Glenn County Office of Emergency Services	Mutual Aid	4/6/2022	Meeting
Gold Ridge Fire Protection District	AB56	3/9/2022	Meeting
Gonzales Volunteer Fire Department	AB56	1/10/2022	Meeting
Grass Valley Fire Department	AB56	4/29/2022	Email
Graton Fire Protection District	AB56	3/9/2022	Meeting
Greenfield Fire Department	AB56	1/10/2022	Meeting
Gridley Fire Department	AB56	2/10/2022	Meeting
Hamilton City Fire Department	AB56	2/9/2022	Meeting
Healdsburg Fire Department	AB56	3/9/2022	Meeting
Herald Fire Protection District	AB56	4/28/2022	Meeting
Hollister Fire Department	AB56	1/13/2022	Meeting
Hopland Fire Protection District	AB56	2/10/2022	Meeting
Hughson Fire Department	AB56	5/5/2022	Meeting
Humboldt Bay Fire Protection District	AB56	3/23/2022	Meeting
Ione Fire Department	AB56	5/5/2022	Presentation
Isleton Fire Department	AB56	4/6/2022	Meeting
Jackson Fire Department	AB56	5/5/2022	Presentation
Jackson Valley Fire Protection District	AB56	5/5/2022	Presentation
Kanawha Fire Protection District	AB56	2/9/2022	Meeting
Kentfield Fire Protection District	AB56	3/17/2022	Meeting
Kenwood Fire Protection District	AB56	3/9/2022	Meeting

TABLE 8-61:
COLLABORATION IN LOCAL WILDFIRE MITIGATION PLANNING
(CONTINUED)

Name of County, City, or Tribal Agency or Civil Society Organization (e.g., Non-Government Organization, Fire Safe Council	Program, Plan, or Document	Last Version of Collaboration	Level of Collaboration
Kern County Administrative Office	Wildfire Safety	3/21/2022	Meeting
Kern County Office of Emergency Services	Wildfire Safety	3/21/2022	Meeting
Keyes Fire Protection District	AB56	5/5/2022	Meeting
King City Volunteer Fire Department	AB56	3/10/2022	Meeting
Kings County Fire Department	AB56	4/13/2022	Meeting
Knights Landing Fire Protection District	AB56	5/10/2022	Meeting
La Honda Fire Brigade	TD-1464S Wildfire Prevention and Mitigation	10/19/2022	Prescribed Burn
La Honda Fire Brigade	TD-1464S Wildfire Prevention and Mitigation	10/4/2022	Prescribed Burn
Lassen County Office of Emergency Services	Mutual Aid	4/6/2022	Meeting
Lathrop-Manteca Fire Protection District	AB56	4/27/2022	Meeting
Liberty Rural County Fire Protection District	AB56	4/6/2022	Meeting
Lincoln Fire Department	AB56	1/27/2022	Meeting
Lincoln Fire Department	Wildfire Safety	3/31/2022	Meeting
Linda Fire Protection District	AB56	4/15/2022	Meeting
Linden-Peters Rural Fire Protection District	AB56	5/4/2022	Meeting
Little Lake Fire Protection District	AB56	3/25/2022	Meeting
Livermore-Pleasanton Fire Department	AB56	1/19/2022	Meeting
Livermore-Pleasanton Fire Department	AB56	1/26/2022	Meeting
Livermore-Pleasanton Fire Department	Emergency Management	10/27/2022	Meeting

TABLE 8-61:
COLLABORATION IN LOCAL WILDFIRE MITIGATION PLANNING
(CONTINUED)

Name of County, City, or Tribal Agency or Civil Society Organization (e.g., Non-Government Organization, Fire Safe Council	Program, Plan, or Document	Last Version of Collaboration	Level of Collaboration
Livermore-Pleasanton Fire Department	Wildfire Safety	11/16/2022	Meeting
Lodi Fire Department	AB56	4/6/2022	Meeting
Los Altos Hills Fire Department CERT	Wildfire Safety	4/14/2022	Meeting
Los Banos Fire Department	AB56	5/27/2022	Meeting
Los Gatos Monte Sereno Police Department	Wildfire Safety	4/14/2022	Meeting
Madison Fire Protection District	AB56	5/10/2022	Meeting
Manteca Fire Department	AB56	5/4/2022	Meeting
Marin County Fire Department	AB56	3/17/2022	Meeting
Marin County Office of Emergency Services	OES Coordination	4/25/2022	Meeting
Marina Fire Department	AB56	1/10/2022	Meeting
Marina Fire Department	AB56	1/10/2022	Meeting
Marine Corps Logistics Base Barstow Fire Department	Wildfire Safety	9/21/2022	Meeting
Marinwood Fire Department	AB56	3/21/2022	Meeting
Marysville Fire Department	AB56	4/15/2022	Meeting
Maxwell Fire Protection District	AB56	4/18/2022	Meeting
Menlo Park Fire Protection District	AB56	1/20/2022	Presentation
Menlo Park Fire Protection District	Wildfire Safety	1/27/2022	Meeting
Menlo Park Fire Protection District	AB56	2/2/2022	Presentation
Menlo Park Fire Protection District	Wildfire Safety	9/7/2022	Presentation
Merced County Fire Department	AB56	4/28/2022	Meeting
Merced Fire Department	AB56	4/22/2022	Meeting
Meridian Fire Protection District	AB56	5/6/2022	Meeting
Millville Fire Protection District	AB56	2/17/2022	Meeting

TABLE 8-61:
COLLABORATION IN LOCAL WILDFIRE MITIGATION PLANNING
(CONTINUED)

Name of County, City, or Tribal Agency or Civil Society Organization (e.g., Non-Government Organization, Fire Safe Council	Program, Plan, or Document	Last Version of Collaboration	Level of Collaboration
Milpitas Fire Department	Wildfire Safety	1/20/2022	Meeting
Milpitas Fire Department	AB56	3/17/2022	Meeting
Milpitas Fire Department	AB56	3/2/2022	Meeting
Milpitas Fire Department	AB56	3/22/2022	Meeting
MISSION COLLEGE	Wildfire Safety	1/20/2022	Meeting
Mi-Wuk Sugar Pine Fire Protection District	AB56	4/21/2022	Meeting
Modesto Fire Department	AB56	5/5/2022	Meeting
Modoc County Sheriff's Department	Mutual Aid	4/6/2022	Meeting
Mokelumne Rural Fire District	AB56	5/4/2022	Meeting
Monterey County Regional Fire District	AB56	1/10/2022	Meeting
Monterey County Regional Fire District	AB56	1/13/2022	Meeting
Monterey Fire Department	AB56	1/10/2022	Meeting
Monterey Peninsula Regional Airport Fire Department	AB56	1/10/2022	Meeting
Montezuma Fire Protection District	AB56	1/6/2022	Meeting
Montezuma Fire Protection District	AB56	4/26/2022	Meeting
Montezuma Fire Protection District	AB56	4/28/2022	Meeting
Montezuma Fire Protection District	AB56	4/6/2022	Meeting
Montezuma Fire Protection District	AB56	5/4/2022	Meeting
Moraga - Orinda Fire Protection District	AB56	3/9/2022	Meeting
Morgan Hill CERT	Wildfire Safety	4/14/2022	Meeting
Morgan Hill Police Department	Wildfire Safety	4/14/2022	Meeting
Mosquito Fire Protection District	Wildfire Safety	4/5/2022	Webinar

**TABLE 8-61:
COLLABORATION IN LOCAL WILDFIRE MITIGATION PLANNING
(CONTINUED)**

Name of County, City, or Tribal Agency or Civil Society Organization (e.g., Non-Government Organization, Fire Safe Council	Program, Plan, or Document	Last Version of Collaboration	Level of Collaboration
Mosquito Fire Protection District	Wildfire Safety	5/17/2022	Meeting
MOTCO Federal Fire Department - Concord	AB56	6/22/2022	Meeting
Mountain Gate Community Services Fire District	AB56	2/17/2022	Meeting
Mountain View Fire Department	AB56	3/17/2022	Meeting
Mountain View Fire Department	AB56	3/2/2022	Meeting
Mountain View Fire Protection District	AB56	5/5/2022	Meeting
Mule Creek State Prison Fire Department	AB56	5/5/2022	Presentation
Murphys Fire Protection District	AB56	4/13/2022	Meeting
Napa County Fire Department	AB56	3/23/2022	Meeting
Napa Fire Department	AB56	3/25/2022	Meeting
Napa State Hospital Fire Department	AB56	3/25/2022	Meeting
NASA Ames Fire Department	AB56	3/2/2022	Meeting
Nevada County Consolidated Fire District	AB56	4/29/2022	Email
Nevada County Office of Emergency Services	Nevada/Yuba/Placer Annual Incident Management Drill	5/24/2022	Training
Nevada County Sheriff's Department	Nevada/Yuba/Placer Annual Incident Management Drill	5/24/2022	Training
Newcastle Fire Protection District	AB56	1/27/2022	Meeting
Newcastle Fire Protection District	Wildfire Safety	3/31/2022	Meeting
Newman Fire Protection District	AB56	5/5/2022	Meeting
North Bay Fire	AB56	3/9/2022	Meeting
North County Fire Authority	AB56	1/20/2022	Presentation
North County Fire Authority	AB56	2/2/2022	Presentation

TABLE 8-61:
COLLABORATION IN LOCAL WILDFIRE MITIGATION PLANNING
(CONTINUED)

Name of County, City, or Tribal Agency or Civil Society Organization (e.g., Non-Government Organization, Fire Safe Council	Program, Plan, or Document	Last Version of Collaboration	Level of Collaboration
North County Fire Authority	Wildfire Safety	9/7/2022	Presentation
North County Fire Protection District of Monterey County	AB56	1/10/2022	Meeting
North County Fire Protection District of Monterey County	AB56	1/10/2022	Meeting
Northern Sonoma County Fire Protection District	AB56	3/9/2022	Meeting
Oakdale Fire Department	AB56	5/5/2022	Meeting
Oakland Fire Department	AB56	1/19/2022	Meeting
Oakland Fire Department	AB56	1/26/2022	Meeting
Oakland Fire Department	Wildfire Safety	11/16/2022	Meeting
Oakland Fire Department	FRW/FLAG Training	3/23/2022	Meeting
Oakland Fire Department	FRW/FLAG Training	6/22/2022	Meeting
Oakland Fire Department	Wildfire Safety	6/27/2022	Meeting
Olivehurst Public Utility District Fire Department	AB56	4/15/2022	Meeting
Ord Bend Community Services District	AB56	2/9/2022	Meeting
Orland Fire Protection District	AB56	2/9/2022	Meeting
Oroville City Fire Department	AB56	3/9/2022	Meeting
Pacific Grove Fire Department	AB56	1/10/2022	Meeting
Pacifica Police Department	Wildfire Safety	1/27/2022	Meeting
Paige Volunteer Fire Department	AB56	1/27/2022	Meeting
Palo Alto Fire Department	Wildfire Safety	1/20/2022	Meeting
Palo Alto Fire Department	AB56	3/17/2022	Meeting
Palo Alto Fire Department	AB56	3/2/2022	Meeting
Palo Alto Office of Emergency Services	Wildfire Safety	4/14/2022	Meeting
Paradise Fire Department	AB56	2/10/2022	Meeting
Patterson Fire Department	AB56	5/5/2022	Meeting

TABLE 8-61:
COLLABORATION IN LOCAL WILDFIRE MITIGATION PLANNING
(CONTINUED)

Name of County, City, or Tribal Agency or Civil Society Organization (e.g., Non-Government Organization, Fire Safe Council	Program, Plan, or Document	Last Version of Collaboration	Level of Collaboration
Penn Valley Fire Protection District	AB56	4/29/2022	Email
Penryn Fire Protection District	AB56	1/27/2022	Meeting
Petaluma Fire Department	AB56	3/9/2022	Meeting
Piedmont Fire Department	AB56	1/19/2022	Meeting
Piedmont Fire Department	Wildfire Safety	11/16/2022	Meeting
Piedmont Fire Department	FRW/FLAG Training	3/23/2022	Meeting
Piedmont Fire Department	FRW/FLAG Training	6/22/2022	Meeting
Pinole Fire Department	AB56	3/9/2022	Meeting
Placer County Fire Department	AB56	1/27/2022	Meeting
Placer County Fire Department	Wildfire Safety	3/31/2022	Meeting
Placer County Office of Emergency Services	Wildfire Safety	3/31/2022	Meeting
Placer County Office of Emergency Services	Nevada/Yuba/Placer Annual Incident Management Drill	5/24/2022	Training
Placer County Sheriff’s Department	Wildfire Safety	3/31/2022	Meeting
Placer County Sheriff’s Department	Nevada/Yuba/Placer Annual Incident Management Drill	5/24/2022	Training
Placer Hills Fire Protection District	AB56	1/27/2022	Meeting
Placer Hills Fire Protection District	Wildfire Safety	3/31/2022	Meeting
Plumas County Office of Emergency Services	Mutual Aid	4/6/2022	Meeting
Porterville Fire Department	AB56	3/10/2022	Meeting
Presidio of Monterey-Fire Department	AB56	1/10/2022	Meeting
Princeton Fire Protection District	AB56	4/25/2022	Meeting
Rancho Adobe Fire Protection District	AB56	3/9/2022	Meeting

**TABLE 8-61:
COLLABORATION IN LOCAL WILDFIRE MITIGATION PLANNING
(CONTINUED)**

Name of County, City, or Tribal Agency or Civil Society Organization (e.g., Non-Government Organization, Fire Safe Council	Program, Plan, or Document	Last Version of Collaboration	Level of Collaboration
Red Bluff Fire Department	AB56	2/18/2022	Meeting
Redding Fire Department	AB56	2/17/2022	Meeting
Redwood City Public Works Department	Wildfire Safety	3/17/2022	Presentation
Redwood City San Carlos Fire Department	AB56	1/20/2022	Presentation
Redwood City San Carlos Fire Department	Wildfire Safety	1/27/2022	Meeting
Redwood City San Carlos Fire Department	TD-1464S Wildfire Prevention and Mitigation	10/4/2022	Prescribed Burn
Redwood City San Carlos Fire Department	AB56	2/2/2022	Presentation
Redwood City San Carlos Fire Department	Wildfire Safety	3/17/2022	Presentation
Redwood City San Carlos Fire Department	Wildfire Safety	9/7/2022	Presentation
Redwood Valley-Calpella Fire Protection District	AB56	3/9/2022	Meeting
Richmond Fire Department	AB56	3/9/2022	Meeting
Rio Dell Fire Protection District	AB56	3/23/2022	Meeting
Rio Vista Fire Department	AB56	1/6/2022	Meeting
Ripon Consolidated Fire Protection District	AB56	4/6/2022	Meeting
Ripon Consolidated Fire Protection District	AB56	5/4/2022	Meeting
River Delta Fire Protection District	AB56	4/28/2022	Meeting
Rocklin Fire Department	AB56	1/27/2022	Meeting
Rocklin Fire Department	Wildfire Safety	3/31/2022	Meeting
Rodeo-Hercules Fire Protection District	AB56	3/9/2022	Meeting
Rohnert Park Department of Public Safety	AB56	3/9/2022	Meeting

TABLE 8-61:
COLLABORATION IN LOCAL WILDFIRE MITIGATION PLANNING
(CONTINUED)

Name of County, City, or Tribal Agency or Civil Society Organization (e.g., Non-Government Organization, Fire Safe Council	Program, Plan, or Document	Last Version of Collaboration	Level of Collaboration
Roseville Fire Department	AB56	1/27/2022	Meeting
Roseville Fire Department	Wildfire Safety	3/31/2022	Meeting
Rough and Ready Fire District	AB56	4/29/2022	Email
Sacramento County Airport System Aircraft Rescue & Firefighting	AB56	5/10/2022	Email
Sacramento Fire Department	AB56	4/7/2022	Meeting
Sacramento Metropolitan Fire District	AB56	4/7/2022	Meeting
Saint Helena Fire Department	AB56	3/23/2022	Meeting
Salida Fire Protection District	AB56	5/5/2022	Meeting
Salinas Fire Department	AB56	1/10/2022	Meeting
Samoa Peninsula Fire Protection District	AB56	4/6/2022	Email
San Andreas Fire Protection District	AB56	4/13/2022	Meeting
San Bernardino County Fire Department	Wildfire Safety	9/22/2022	Meeting
San Bernardino County Fire Department	AB56	3/24/2022	Meeting
San Bruno Fire Department	AB56	1/20/2022	Presentation
San Bruno Fire Department	AB56	2/2/2022	Presentation
San Bruno Fire Department	Wildfire Safety	3/25/2022	Meeting
San Bruno Fire Department	Wildfire Safety	9/7/2022	Presentation
San Francisco Airport	Wildfire Safety	1/27/2022	Meeting
San Francisco Fire Department	AB56	1/13/2022	Meeting
San Jose Fire Department	Wildfire Safety	1/20/2022	Meeting
San Jose Fire Department	AB56	3/17/2022	Meeting
San Jose Fire Department	AB56	3/2/2022	Meeting
San Jose Fire Department	AB56	3/22/2022	Meeting
San Jose Office of Emergency Services	Wildfire Safety	3/25/2022	Meeting

TABLE 8-61:
COLLABORATION IN LOCAL WILDFIRE MITIGATION PLANNING
(CONTINUED)

Name of County, City, or Tribal Agency or Civil Society Organization (e.g., Non-Government Organization, Fire Safe Council	Program, Plan, or Document	Last Version of Collaboration	Level of Collaboration
San Juan Bautista Fire Department	AB56	1/13/2022	Meeting
San Luis Obispo County Office of Emergency Services	Wildfire Safety	6/9/2022	Meeting
San Mateo Consolidated Fire	Evacuation for Peninsula Bayside	1/13/2022	Meeting
San Mateo Consolidated Fire	Evacuation for Peninsula Bayside	1/13/2022	Meeting
San Mateo Consolidated Fire	AB56	1/20/2022	Presentation
San Mateo Consolidated Fire	Wildfire Safety	1/27/2022	Meeting
San Mateo Consolidated Fire	TD-1464S Wildfire Prevention and Mitigation	10/4/2022	Prescribed Burn
San Mateo Consolidated Fire	AB56	2/2/2022	Presentation
San Mateo County Department of Emergency Management	Evacuation for Peninsula Bayside	1/13/2022	Meeting
San Mateo County Department of Emergency Management	Evacuation for Peninsula Bayside	1/13/2022	Meeting
San Mateo County Department of Emergency Management	TD-1464S Wildfire Prevention and Mitigation	10/26/2022	Meeting
San Mateo County Department of Emergency Management	TD-1464S Wildfire Prevention and Mitigation	11/8/2022	Meeting
San Mateo County Department of Emergency Management	Wildfire Safety	3/25/2022	Meeting
San Mateo County Fire	AB56	1/20/2022	Presentation
San Mateo County Fire	AB56	2/2/2022	Presentation
San Mateo County Fire	Wildfire Safety	9/7/2022	Presentation
San Mateo County Public Safety Communications	TD-1464S Wildfire Prevention and Mitigation	11/8/2022	Meeting
San Mateo County Public Safety Communications	AB56	2/2/2022	Presentation

TABLE 8-61:
COLLABORATION IN LOCAL WILDFIRE MITIGATION PLANNING
(CONTINUED)

Name of County, City, or Tribal Agency or Civil Society Organization (e.g., Non-Government Organization, Fire Safe Council	Program, Plan, or Document	Last Version of Collaboration	Level of Collaboration
San Mateo County Public Works Department	TD-1464S Wildfire Prevention and Mitigation	11/8/2022	Meeting
San Quentin State Prison Fire Department	AB56	3/14/2022	Meeting
San Rafael Fire Department	AB56	3/21/2022	Meeting
San Ramon Valley Fire Protection District	AB56	3/9/2022	Meeting
Sanger Fire Department	AB56	4/22/2022	Meeting
Santa Clara County Fire Department	Wildfire Safety	1/20/2022	Meeting
Santa Clara County Fire Department	AB56	3/17/2022	Meeting
Santa Clara County Fire Department	AB56	3/2/2022	Meeting
Santa Clara County Emergency Managers Association	Wildfire Safety	1/13/2022	Meeting
Santa Clara County Emergency Managers Association	Wildfire Safety	2/10/2022	Meeting
Santa Clara County Emergency Managers Association	Wildfire Safety	4/14/2022	Meeting
Santa Clara County Fire Safe Council	Fire Season Coordination	3/14/2022	Meeting
Santa Clara County Office of Emergency Management	Wildfire Safety	3/25/2022	Meeting
Santa Clara County Office of Emergency Management	Wildfire Safety	4/14/2022	Meeting
Santa Clara County Office of Emergency Management	Wildfire Safety	6/9/2022	Meeting
Santa Clara Fire Department	Wildfire Safety	1/20/2022	Meeting
Santa Clara Fire Department	AB56	3/17/2022	Meeting
Santa Clara Fire Department	AB56	3/2/2022	Meeting
Santa Clara Fire Department	Wildfire Safety	4/14/2022	Meeting

TABLE 8-61:
COLLABORATION IN LOCAL WILDFIRE MITIGATION PLANNING
(CONTINUED)

Name of County, City, or Tribal Agency or Civil Society Organization (e.g., Non-Government Organization, Fire Safe Council	Program, Plan, or Document	Last Version of Collaboration	Level of Collaboration
Santa Clara Valley Water District, Valley Water	Los Banos-Pacheco 70kV	1/20/2022	Meeting
Santa Clara Valley Water District, Valley Water	Wildfire Safety	2/10/2022	Meeting
Santa Clara Valley Water District, Valley Water	Wildfire Safety	2/24/2022	Meeting
Santa Rosa Fire Department	AB56	3/9/2022	Meeting
Schell-Vista Fire Protection District	AB56	3/9/2022	Meeting
Scotts Valley Fire Protection District	AB56	4/27/2022	Meeting
Seaside Fire Department	AB56	1/10/2022	Meeting
Seaside Fire Department	AB56	1/10/2022	Meeting
Sebastopol Fire Department	AB56	3/9/2022	Meeting
Selma Fire Department	AB56	4/29/2022	Meeting
Shasta CSD/Shasta Fire Protection District	AB56	2/17/2022	Meeting
Shasta Lake Fire Protection District	AB56	2/17/2022	Meeting
Sierra County Office of Emergency Services	Mutual Aid	4/6/2022	Meeting
SIERRA, PACIFIC INDUSTRIES	Sierra Pacific Industries & Cal Fire Wildland Fire	5/6/2022	Meeting
Siskiyou County Office of Emergency Services	Mutual Aid	4/6/2022	Meeting
Soledad Correctional Training Facility – Fire Department	AB56	3/10/2022	Meeting
Sonoma County Fire District	AB56	3/9/2022	Meeting
Sonoma Valley Fire & Rescue Authority	AB56	3/9/2022	Meeting
Sonora Fire Department	AB56	4/21/2022	Meeting
South Bay Central Coast Community Member	Wildfire Safety	6/9/2022	Meeting

TABLE 8-61:
COLLABORATION IN LOCAL WILDFIRE MITIGATION PLANNING
(CONTINUED)

Name of County, City, or Tribal Agency or Civil Society Organization (e.g., Non-Government Organization, Fire Safe Council	Program, Plan, or Document	Last Version of Collaboration	Level of Collaboration
South Bay Regional Public Safety Training Consortium	Wildfire Safety	1/20/2022	Meeting
South Placer Fire District	AB56	1/27/2022	Meeting
South Placer Fire District	Wildfire Safety	3/31/2022	Meeting
South San Francisco Fire Department	AB56	1/20/2022	Presentation
South San Francisco Fire Department	AB56	2/2/2022	Presentation
South San Francisco Fire Department	Wildfire Safety	9/7/2022	Presentation
South Santa Clara County Fire District	AB56	3/2/2022	Meeting
Southern California Edison	Wildfire Safety	6/9/2022	Meeting
Southern Marin Fire Protection District	AB56	3/17/2022	Meeting
Southern Trinity Volunteer Fire Department	AB56	2/7/2022	Meeting
Springlake Fire Protection District	AB56	5/10/2022	Meeting
Stanislaus Consolidated Fire Protection District	AB56	5/5/2022	Meeting
Stanislaus Consolidated Fire Protection District	AB56	5/5/2022	Meeting
Stanislaus County Office of Emergency Services	AB56	5/5/2022	Meeting
State of California Governor’s Office of Emergency Services (CAL OES)	Wildfire Safety	6/2/2022	Meeting
State of California Governor’s Office of Emergency Services (CAL OES)	Emergency Management	10/27/2022	Meeting
Stockton Fire Department	AB56	4/6/2022	Meeting
Stockton Fire Department	AB56	5/4/2022	Meeting
Suisun City Fire Department	AB56	1/6/2022	Meeting

TABLE 8-61:
COLLABORATION IN LOCAL WILDFIRE MITIGATION PLANNING
(CONTINUED)

Name of County, City, or Tribal Agency or Civil Society Organization (e.g., Non-Government Organization, Fire Safe Council	Program, Plan, or Document	Last Version of Collaboration	Level of Collaboration
Suisun City Fire Department	AB56	4/26/2022	Meeting
Suisun Fire Protection District	AB56	1/6/2022	Meeting
Sunnyvale Department of Public Safety	Wildfire Safety	1/20/2022	Meeting
Sunnyvale Department of Public Safety	AB56	3/17/2022	Meeting
Sunnyvale Department of Public Safety	AB56	3/2/2022	Meeting
Sunnyvale Department of Public Safety	Wildfire Safety	4/14/2022	Meeting
Sunnyvale Department of Public Safety	Wildfire Safety	6/9/2022	Meeting
Sutter County Fire Department	AB56	5/6/2022	Meeting
Sutter County Office of Emergency Services	Mutual Aid	4/6/2022	Meeting
Sutter Creek Fire Protection District	AB56	5/5/2022	Presentation
Tehama County Administrative Office	Sierra Pacific Industries & Cal Fire Wildland Fire	5/6/2022	Meeting
Tehama County Sheriff's Department	Mutual Aid	4/6/2022	Meeting
Tehama County Sheriff's Department	Sierra Pacific Industries & Cal Fire Wildland Fire	5/6/2022	Meeting
Thornton Rural Fire Protection District	AB56	4/28/2022	Meeting
Thornton Rural Fire Protection District	AB56	4/6/2022	Meeting
Thornton Rural Fire Protection District	AB56	5/4/2022	Meeting
Tiburon Fire Protection District	AB56	3/18/2022	Meeting
Tracy Fire Department	AB56	4/6/2022	Meeting
Travis Air Force Base Fire Department	AB56	5/3/2022	Meeting

TABLE 8-61:
COLLABORATION IN LOCAL WILDFIRE MITIGATION PLANNING
(CONTINUED)

Name of County, City, or Tribal Agency or Civil Society Organization (e.g., Non-Government Organization, Fire Safe Council	Program, Plan, or Document	Last Version of Collaboration	Level of Collaboration
Trinity County Office of Emergency Services	Mutual Aid	4/6/2022	Meeting
Tulare County Fire Department	AB56	3/10/2022	Meeting
Tuolumne County Fire Department	Wildfire Safety	10/13/2022	Meeting
Tuolumne County Fire Department	AB56	4/21/2022	Meeting
Tuolumne Fire District	AB56	4/21/2022	Meeting
Tuolumne Rancheria Fire Department	Wildfire Safety	10/13/2022	Meeting
Tuolumne Rancheria Fire Department	AB56	4/21/2022	Meeting
Turlock Fire Department and Emergency Services	AB56	5/5/2022	Meeting
Turlock Rural Fire Protection District	AB56	5/5/2022	Meeting
Twain Harte Community Services District Fire Department	Wildfire Safety	10/13/2022	Meeting
Twain Harte Community Services District Fire Department	AB56	4/21/2022	Meeting
U.S. Forest Service – Plumas National Forest	AB56	3/1/2022	Phone Call
U.S. Forest Service – Lassen National Forest	Sierra Pacific Industries & Cal Fire Wildland Fire	5/6/2022	Meeting
U.S. Forest Service – Mendocino National Forest	Sierra Pacific Industries & Cal Fire Wildland Fire	5/6/2022	Meeting
U.S. Forest Service – Modoc National Forest – MacDoel Ranger District	AB56	3/1/2022	Phone Call
U.S. Forest Service – Pacific Southwest Region, North Operations	AB56	3/1/2022	Phone Call

TABLE 8-61:
COLLABORATION IN LOCAL WILDFIRE MITIGATION PLANNING
(CONTINUED)

Name of County, City, or Tribal Agency or Civil Society Organization (e.g., Non-Government Organization, Fire Safe Council	Program, Plan, or Document	Last Version of Collaboration	Level of Collaboration
U.S. Forest Service – Region 5 Headquarters	AB56	3/1/2022	Phone Call
U.S. Forest Service – Region 5 Headquarters	Sierra Pacific Industries & Cal Fire Wildland Fire	5/6/2022	Meeting
U.S. Forest Service – Sequoia National Forest	Fire Season Coordination	4/21/2022	Meeting
U.S. Forest Service – Shasta Trinity National Forest	Sierra Pacific Industries & Cal Fire Wildland Fire	5/6/2022	Meeting
U.S. Forest Service – Six Rivers National Forest Headquarters	Sierra Pacific Industries & Cal Fire Wildland Fire	5/6/2022	Meeting
United States Bureau of Land Management - Redding	AB56	2/28/2022	Meeting
United States Forest Service – Sierra National Forest	Hydro Re-Licensing	2/22/2022	Meeting
United States Forest Service – Sierra National Forest	Hydro Re-Licensing	3/15/2022	Meeting
United States Forest Service - Sierra National Forest	Hydro Re-Licensing	3/25/2022	Meeting
United States Forest Service – Sierra National Forest	Hydro Re-Licensing	3/29/2022	Meeting
United States Forest Service – Sierra National Forest	Hydro Re-Licensing	3/8/2022	Meeting
United States Forest Service – Sierra National Forest	Fire Season Coordination	4/21/2022	Meeting
Vacaville Fire Department	AB56	1/6/2022	Meeting
Vacaville Fire Department	AB56	4/26/2022	Meeting
Vacaville Fire Protection District	AB56	4/26/2022	Meeting
Vallejo Fire Department	AB56	1/6/2022	Meeting
Vallejo Fire Department	AB56	1/6/2022	Meeting
Vallejo Fire Department	AB56	4/26/2022	Meeting
Victorville Fire Department	Wildfire Safety	9/22/2022	Meeting

TABLE 8-61:
COLLABORATION IN LOCAL WILDFIRE MITIGATION PLANNING
(CONTINUED)

Name of County, City, or Tribal Agency or Civil Society Organization (e.g., Non-Government Organization, Fire Safe Council	Program, Plan, or Document	Last Version of Collaboration	Level of Collaboration
Visalia Fire Department	AB56	3/10/2022	Meeting
Walnut Grove Fire Protection District	AB56	4/28/2022	Meeting
Waterloo – Morada Rural Fire Protection District	AB56	5/4/2022	Meeting
West Plainfield Fire Protection District	AB56	5/10/2022	Meeting
West Point Fire Protection District	AB56	4/13/2022	Meeting
West Sacramento Fire Department	AB56	5/10/2022	Meeting
West Stanislaus Fire Protection District	AB56	5/5/2022	Meeting
Westport Fire Protection District	AB56	5/5/2022	Meeting
Westport Volunteer Fire Department	AB56	5/5/2022	Meeting
Wheatland Fire Authority	AB56	4/15/2022	Meeting
Williams Fire Protection Authority	AB56	4/18/2022	Meeting
Willow Oak Fire Protection District	AB56	5/10/2022	Meeting
Willows City Fire Department	AB56	2/9/2022	Meeting
Willows Rural Fire Protection District	AB56	2/9/2022	Meeting
Wilton Fire Protection District	AB56	4/28/2022	Meeting
Winters Fire Department	AB56	5/10/2022	Meeting
Woodbridge Rural Fire Protection District	AB56	4/6/2022	Meeting
Woodbridge Rural Fire Protection District	AB56	4/6/2022	Meeting
Woodbridge Rural Fire Protection District	AB56	5/4/2022	Meeting
Woodland	AB56	5/10/2022	Meeting

TABLE 8-61:
COLLABORATION IN LOCAL WILDFIRE MITIGATION PLANNING
(CONTINUED)

Name of County, City, or Tribal Agency or Civil Society Organization (e.g., Non-Government Organization, Fire Safe Council	Program, Plan, or Document	Last Version of Collaboration	Level of Collaboration
Woodland Avenue Fire Protection District	AB56	5/5/2022	Meeting
Woodland Fire Department	AB56	5/10/2022	Meeting
Woodside Fire Protection District	AB56	1/20/2022	Presentation
Woodside Fire Protection District	TD-1464S Wildfire Prevention and Mitigation	10/4/2022	Prescribed Burn
Woodside Fire Protection District	AB56	2/2/2022	Presentation
Woodside Fire Protection District	Wildfire Safety	2/9/2022	Meeting
Yocha Dehe Fire Department	AB56	5/10/2022	Meeting
Yolo Fire Protection District	AB56	5/10/2022	Meeting
Yuba City Fire Department	AB56	5/6/2022	Meeting
Yuba County Office of Emergency Services	Mutual Aid	4/6/2022	Meeting
Zamora Fire Protection District	AB56	5/10/2022	Meeting
Zone Haven	Evacuation for Peninsula Bayside	1/13/2022	Meeting
Zone Haven	Evacuation for Peninsula Bayside	1/13/2022	Meeting

TABLE 8-63:
SHARING BEST PRACTICES WITH OTHER UTILITIES

Best Practice Subject	Dates of Collaboration (YYYY-YYYY)	Technical or Program-matic	Corporation Partner(s)	Description of Best Practice Sharing or Collaborating	Outcome
Covered Conductor Effectiveness Study	2021-present	Technical	• PG&E • Southern California Edison Company (SCE) • San Diego Gas & Electric Company (SDG&E) • PacifiCorp • Bear Valley • Liberty Utilities	Coordinate to develop a consistent approach to evaluating the long-term risk reduction and cost-effectiveness of covered conductor deployment, including: The effectiveness of covered conductor in the field in comparison to alternative initiatives. How covered conductor installation compares to other initiatives in its potential to reduce PSPS risk.	Developed Joint IOU FMEA for covered conductors. Benchmarking report for historic testing informing performance of Covered Conductor. Collaborative and complementary testing reports from SCE and PG&E. With SDG&E testing report expected in 2023. Continue work on lessons learned in 2023.
Vegetation Clearance Study	2022	Technical	• PG&E • SCE • SDG&E	The objectives of this study are to: Establish uniform data collection standards; Create a cross-utility database of tree-caused risk events (i.e., outages and ignitions caused by vegetation contact); and Incorporate biotic and abiotic factors into the determination of outage and ignition risk caused by vegetation contact.	Ongoing

TABLE 8-63:
SHARING BEST PRACTICES WITH OTHER UTILITIES
(CONTINUED)

Best Practice Subject	Dates of Collaboration (YYYY-YYYY)	Technical or Program-matic	Corporation Partner(s)	Description of Best Practice Sharing or Collaborating	Outcome
Risk Spend Efficiency (RSE)	2021-2022 (Ongoing with SCE and SDG&E)	Technical	• PG&E • SCE • SDG&E • PacifiCorp • Bear Valley • Liberty Utilities	Develop a more standardized approach to the inputs and assumptions used for RSE calculations. This working group will focus on addressing the inconsistencies between the utilities' inputs and assumptions, used for their RSE calculations, which will allow for: Collaboration among utilities; Stakeholder and academic expert input; and Increased transparency.	Ongoing Consistently interpret the WMP guidelines on the aspects of risk reduction and RSE, including: Ongoing control and compliance programs compared to mitigation program. Effectiveness among utilities for various programs like covered conductor, undergrounding, inspection, maintenance, and VM. Information is brought back within the utilities to incorporate feedback from the benchmarking and making adjustments to RSE calculations where reasonable.
Risk Modeling	2021-present	Technical	• PG&E • SCE • SDG&E • PacifiCorp • Bear Valley	OEIS Risk Modeling Work Group Develop a more consistent statewide approach to wildfire risk modeling. A working group to address wildfire risk modeling will allow for: Collaboration among the utilities; Stakeholder and academic expert input; and	Ongoing Identified best practices on modeling with the intent of establishing modeling standards across the groups

			• Liberty Utilities	Increased transparency. Ad-hoc collaboration sessions to align on best practices.	
EPSS	2021-2022	Technical and Programmatic	• PG&E • SCE • SDG&E	The purpose of these discussions is to provide insight into what types of protective device setting changes other west coast utilities, with similar wildfire risks to PG&E, are implementing to mitigate the risk of wildfire ignitions from utility equipment. Previous discussions were limited to other large California utilities such as SCE and SDG&E. These discussions expanded to include several other utilities in Washington State, Oregon and British Columbia.	Complete These discussions indicate that many other utilities have implemented fast trip settings for several years. SDG&E has had some form of fast trip settings for about 10 years, SCE started implementing their fast trip schemes in 2018, and Avista has had fast trip settings for several years. PacifiCorp performed there first systemwide implementation in 2021. BC Hydro has only performed testing and a limited pilot on one distribution circuit. Other utilities are also looking at new technologies to detect high impedance faults, detecting falling or broken conductors and sensitive ground settings. SDG&E has implemented Sensitive Ground Fault and High Impedance Fault detection settings on their system. Most other of these are in the testing or pilot phase in evaluating these new technologies.

PSPS	2021-ongoing		• SCE • SDG&E	As part of the monthly Joint Utility PSPS Working Group, PG&E shares all lessons learned and best practices pertaining to: All aspects of communications practices with public safety partners, including all technology and all notifications, with the goal of collaborating on best practices for communication with public safety partners before, during, and after a proactive de-energization. All aspects of their communications practices with emergency responders and local governments, including all technology and all notifications, to achieve the Commission's goal of ensuring the public receives timely notice of proactive de-energizations. The exchange of geospatial information with public safety partners in preparation for an imminent PSPS event and during a PSPS event. All aspects of developing and maintaining updated lists of public safety partners on PSPS secure web portals. All aspects of developing and maintaining updated lists of critical facilities and infrastructure customers on PSPS secure web portals. Developing and updating contact information and alternative means of contact regarding PSPS events for all MBL customers and customers that use electricity to maintain necessary life functions. Working, in advance of each wildfire season and during each wildfire season, with local jurisdictions, in a proactive manner, to identify and communicate with all people in a de-energized area, including visitors. Developing notification and communication protocols and systems to reach all customers and communication in an understandable manner. Developing a notification strategy that considers, among other things, geographic and cultural demographics (including all languages used and where used) in advance of fire season. All aspects of the backup power program and share all feedback from critical facilities and infrastructure	Ongoing

				customers on how the utilities are assisting these customers to meet their backup power needs related to pro-active de-energizations. All aspects of their programs to update lists of public safety partners and conduct communication exercises with public safety partners in advance of wildfire season. Feedback from public safety partners on how utilities can improve their response to concurrent emergencies. All aspects of developing and maintaining updated lists of critical facilities and infrastructure customer 24-hour primary/secondary points of contact. Developing and implementing, in advance of wildfire season, a communications strategy to rely on during a proactive de-energization when restrictions due to the power loss exist, Quarterly: Share all best practices and lessons learned relevant to development of a consistent format for reporting, in the 10-day post-event report, compliance with all the notice guidelines (both mandatory and discretionary) set forth in the PSPS Guidelines and any other applicable laws, rules, and regulations. PG&E, SCE, and SDG&E must each provide information on the following notice topics, at a minimum, in the 10-day post-event reports: The time the utility activated its Emergency Operations Center, the time the utility determined it was likely to de-energize, and the time the utility notified public safety partners; Whether public safety partners/priority notification entities received notice 48-72 hours in advance of anticipated de-energization; Whether all other affected customers/populations received notice 24-48 hours in advance of anticipated de-energization; Whether all affected customers/populations received notice 1-4 hours in advance of anticipated de-energization;	

				Whether all affected customers/populations received notice when the de-energization was initiated; Whether all affected customers/populations received notice immediately before re-energization begins; and Whether all affected customers/populations received notice when re-energization was complete. In a report, as designated by the Commission's Safety and Enforcement Division, each utility shall respond to any failure to provide notice consistent with the guidelines with an explanation of what caused these failures and how the utility will correct those failures.	
Undergrounding	Q4 2021-Ongoing	Technical and Programmatic	• PacifiCorp • SDG&E • Florida Power & Light	Ad-hoc discussions related to programmatic best practices with continued discussions as technical and programmatic topics arise including, but not limited to: Contracting strategies; Construction standards; Risk prioritization; Program structure; 3rd party coordination; Design standards; and Permitting challenges.	Ongoing
Distribution Aerial Inspections	Q2 2022-Ongoing	Technical and Programmatic	• SDG&E • SCE • Duke Energy • Southern Company	Discussion related to programmatic and technical tops including but not limited to: Size (scope) of the aerial program; Budget of the aerial program; Breakdown of aerial program (Heli, Drone, Drone + Inspector); Criteria used to select candidate population; Number of aerial images captured per structure; Aerial inspections per hour and day; Platform used for the aerial program; and Future Goals for the aerial program.	Ongoing

Appendix F.4: 9. Public Safety Power Shutoff

The electrical corporation must provide all detailed documentation from Section 9 in this appendix.

Appendix F.4.1: 9.1.2 Identification of Frequently De-Energized Circuits

TABLE 9-2:
LIST OF FREQUENTLY DE-ENERGIZED CIRCUITS

Entry Number	ID of Circuit	Circuit Name	Transmission (Tx)/ Distribution (Dx)	County	Dates of Outages	Number of Customers Served by Circuit (as of December 1, 2022)	Number of Customers Affected	Measures Taken, or Planned to Be Taken, to Reduce the Need for and Impact of Future PSPS of Circuit
1	152101101	ALLEGHANY 1101	Dx	SIERRA	10/9/2019	1,036	1,043	• 1 Sectionalizing device added or replaced • Temporary Generation deployed that benefited 994 customers
					10/23/2019		1,038	
					10/26/2019		1,037	
					9/7/2020		1,028	
					9/27/2020		1,032	
					10/14/2020		957	
					10/25/2020		1,033	
2	152101102	ALLEGHANY 1102	Dx	NEVADA	10/9/2019	151	151	• 0.4 miles of overhead hardening completed
					10/23/2019		151	
					10/26/2019		152	
					9/7/2020		151	
					9/27/2020		153	
					10/25/2020		153	
3	163561101	ALPINE 1101	Dx	ALPINE	10/9/2019	278	278	• Mitigated by PSPS protocol
					10/23/2019		278	
					10/26/2019		277	
					9/7/2020		276	
					9/27/2020		278	
					10/25/2020		278	

TABLE 9-2:
LIST OF FREQUENTLY DE-ENERGIZED CIRCUITS
(CONTINUED)

Entry Number	ID of Circuit	Circuit Name	Transmission (Tx)/ Distribution (Dx)	County	Dates of Outages	Number of Customers Served by Circuit (as of December 1, 2022)	Number of Customers Affected	Measures Taken, or Planned to Be Taken, to Reduce the Need for and Impact of Future PSPS of Circuit
4	163561102	ALPINE 1102	Dx	ALPINE	10/9/2019	306	303	• Mitigated by PSPS protocols
					10/23/2019		303	
					10/26/2019		304	
					9/7/2020		303	
					9/27/2020		303	
					10/25/2020		304	
5	103261103	ANDERSON 1103	Dx	SHASTA	10/9/2019	895	886	• 3 Sectionalizing devices added or replaced
					10/26/2019		886	
					11/20/2019		436	
					10/21/2020		437	
					10/25/2020		438	
					8/17/2021		68	
					10/11/2021		68	
6	42861101	ANNAPOLIS 1101	Dx	SONOMA	10/9/2019	223	219	• Mitigated by PSPS protocols
					10/23/2019		9	
					10/26/2019		218	
					10/25/2020		222	
7	153661103	APPLE HILL 1103	Dx	EL DORADO	10/14/2018	1,269	1,258	
					10/9/2019		1,256	
					10/23/2019		1,256	
					10/26/2019		1,256	

TABLE 9-2:
LIST OF FREQUENTLY DE-ENERGIZED CIRCUITS
(CONTINUED)

Entry Number	ID of Circuit	Circuit Name	Transmission (Tx)/ Distribution (Dx)	County	Dates of Outages	Number of Customers Served by Circuit (as of December 1, 2022)	Number of Customers Affected	Measures Taken, or Planned to Be Taken, to Reduce the Need for and Impact of Future PSPS of Circuit
					9/7/2020		1,260	
					9/27/2020		1,261	
					10/25/2020		1,266	
8	153661104	APPLE HILL 1104	Dx	EL DORADO	10/14/2018	2,427	2,192	
					10/9/2019		2,424	
					10/23/2019		2,425	
					10/26/2019		2,205	
					9/7/2020		2,413	
					9/27/2020		2,425	
					10/25/2020		2,428	
9	153662102	APPLE HILL 2102	Dx	EL DORADO	10/14/2018	4,634	4,373	• 1.3 miles of overhead hardening completed
					10/9/2019		4,382	
					10/23/2019		4,384	
					10/26/2019		4,379	
					9/7/2020		4,375	
					9/27/2020		4,386	
					10/25/2020		4,397	
10	62081101	ARBUCKLE 1101	Dx	COLUSA	10/25/2020	595	3	• 1 Sectionalizing device added or replaced
					8/17/2021		3	
					9/20/2021		3	
					10/11/2021		3	

TABLE 9-2:
LIST OF FREQUENTLY DE-ENERGIZED CIRCUITS
(CONTINUED)

Entry Number	ID of Circuit	Circuit Name	Transmission (Tx)/ Distribution (Dx)	County	Dates of Outages	Number of Customers Served by Circuit (as of December 1, 2022)	Number of Customers Affected	Measures Taken, or Planned to Be Taken, to Reduce the Need for and Impact of Future PSPS of Circuit
11	62081104	ARBUCKLE 1104	Dx	COLUSA	10/9/2019	1,142	1,135	
					10/26/2019		13	
					11/20/2019		13	
					10/25/2020		13	
					8/17/2021		12	
					9/20/2021		13	
					10/11/2021		12	
12	103191101	BANGOR 1101	Dx	YUBA	6/8/2019	1,966	2,290	• 10 Sectionalizing devices added or replaced • 0.2 miles of overhead hardening completed
					9/23/2019		2,299	
					9/25/2019		2,299	
					10/9/2019		2,299	
					10/23/2019		2,297	
					10/26/2019		2,299	
					9/7/2020		291	
					9/27/2020		391	
					10/14/2020		110	
					10/25/2020		2,136	
13	152701107	BELL 1107	Dx	PLACER	10/9/2019	1,498	1,420	• 2 Sectionalizing devices added or replaced • Mitigated by PSPS protocols
					10/23/2019		833	
					10/26/2019		855	

TABLE 9-2:
LIST OF FREQUENTLY DE-ENERGIZED CIRCUITS
(CONTINUED)

Entry Number	ID of Circuit	Circuit Name	Transmission (Tx)/ Distribution (Dx)	County	Dates of Outages	Number of Customers Served by Circuit (as of December 1, 2022)	Number of Customers Affected	Measures Taken, or Planned to Be Taken, to Reduce the Need for and Impact of Future PSPS of Circuit
14	152701108	BELL 1108	Dx	PLACER	10/9/2019	3,418	3,618	• 1 Sectionalizing device added or replaced • Mitigated by PSPS protocols
					10/23/2019		725	
					10/26/2019		1,859	
					10/25/2020		1,559	
15	103751101	BIG BEND 1101	Dx	BUTTE	9/23/2019	279	190	
					9/25/2019		190	
					10/5/2019		191	
					10/9/2019		191	
					10/23/2019		192	
					10/26/2019		192	
					9/7/2020		234	
					9/27/2020		237	
					10/14/2020		237	
					10/21/2020		239	
					10/25/2020		239	
					8/17/2021		259	
					10/11/2021		264	
16	103751102	BIG BEND 1102	Dx	BUTTE	9/23/2019	156	368	
					9/25/2019		368	
					10/5/2019		368	
					10/9/2019		368	

TABLE 9-2:
LIST OF FREQUENTLY DE-ENERGIZED CIRCUITS
(CONTINUED)

Entry Number	ID of Circuit	Circuit Name	Transmission (Tx)/ Distribution (Dx)	County	Dates of Outages	Number of Customers Served by Circuit (as of December 1, 2022)	Number of Customers Affected	Measures Taken, or Planned to Be Taken, to Reduce the Need for and Impact of Future PSPS of Circuit
					10/23/2019		366	• 0.4 miles of overhead hardening completed • 22-line miles undergrounded
					10/26/2019		366	
					9/7/2020		318	
					9/27/2020		9	
					10/14/2020		80	
					10/21/2020		80	
					10/25/2020		81	
17	152301 101	BONNIE NOOK 1101	Dx	PLACER	10/14/2018	347	493	
					10/9/2019		496	
					10/23/2019		496	
					10/26/2019		496	
					9/7/2020		486	
					9/27/2020		490	
					10/25/2020		489	
18	152301102	BONNIE NOOK 1102	Dx	PLACER	10/14/2018	525	518	
					10/9/2019		520	
					10/23/2019		522	
					10/26/2019		522	
					9/7/2020		521	
					9/27/2020		522	
					10/25/2020		522	

TABLE 9-2:
LIST OF FREQUENTLY DE-ENERGIZED CIRCUITS
(CONTINUED)

Entry Number	ID of Circuit	Circuit Name	Transmission (Tx)/ Distribution (Dx)	County	Dates of Outages	Number of Customers Served by Circuit (as of December 1, 2022)	Number of Customers Affected	Measures Taken, or Planned to Be Taken, to Reduce the Need for and Impact of Future PSPS of Circuit
19	192461 102	BRIDGEVILLE 1102	Dx	HUMBOLDT	10/9/2019	251	263	• Mitigated by PSPS protocols
					10/26/2019		264	
					9/7/2020		262	
					10/14/2020		39	
					10/25/2020		269	
20	152921 101	BROWNS VALLEY 1101	Dx	YUBA	9/23/2019	592	565	• Mitigated by PSPS protocols
					9/25/2019		565	
					10/9/2019		570	
					10/23/2019		569	
					10/26/2019		569	
					10/25/2020		116	
21	152481102	BRUNSWICK 1102	Dx	NEVADA	9/25/2019	1,393	1,379	• Mitigated by PSPS protocols • Temporary Generation deployed
					10/9/2019		1,380	
					10/23/2019		1,378	
					10/26/2019		1,378	
					9/7/2020		1,378	
					9/27/2020		328	
					10/25/2020		1,381	

TABLE 9-2:
LIST OF FREQUENTLY DE-ENERGIZED CIRCUITS
(CONTINUED)

Entry Number	ID of Circuit	Circuit Name	Transmission (Tx)/ Distribution (Dx)	County	Dates of Outages	Number of Customers Served by Circuit (as of December 1, 2022)	Number of Customers Affected	Measures Taken, or Planned to Be Taken, to Reduce the Need for and Impact of Future PSPS of Circuit
22	152481103	BRUNSWICK 1103	Dx	NEVADA	10/9/2019 10/23/2019 10/26/2019 9/7/2020 10/25/2020	3,454	3,199 3,197 3,198 3,177 3,198	• 6 Sectionalizing devices added or replaced • 1 MSO device replaced • 29.2 miles of overhead hardening completed • 0.1 line miles undergrounded • Mitigated by PSPS protocols • Temporary Generation deployed that benefited 4185 customers
23	152481104	BRUNSWICK 1104	Dx	NEVADA	10/9/2019 10/23/2019 10/26/2019 9/7/2020 10/25/2020	2,523	2,522 2,520 2,521 2,508 2,520	• 1 Sectionalizing device added or replaced • Mitigated by PSPS protocols • Temporary Generation deployed that benefited 4184 customers

TABLE 9-2:
LIST OF FREQUENTLY DE-ENERGIZED CIRCUITS
(CONTINUED)

Entry Number	ID of Circuit	Circuit Name	Transmission (Tx)/ Distribution (Dx)	County	Dates of Outages	Number of Customers Served by Circuit (as of December 1, 2022)	Number of Customers Affected	Measures Taken, or Planned to Be Taken, to Reduce the Need for and Impact of Future PSPS of Circuit
24	152481105	BRUNSWICK 1105	Dx	NEVADA	9/25/2019	3,585	3,400	• 1 Sectionalizing device added or replaced • 3 MSO device replaced • Mitigated by PSPS protocols • Temporary Generation deployed that benefited 4184 customers
					10/9/2019		3,666	
					10/23/2019		3,665	
					10/26/2019		3,666	
					9/7/2020		3,675	
					9/27/2020		1,831	
					10/25/2020		3,687	
25	152481106	BRUNSWICK 1106	Dx	NEVADA	9/25/2019	4,124	4,475	• 2.6 miles of overhead hardening completed • 0.2 line miles undergrounded • Mitigated by PSPS protocols • Temporary Generation deployed
					10/9/2019		4,475	
					10/23/2019		4,473	
					10/26/2019		4,474	
					9/7/2020		4,480	
					9/27/2020		360	
					10/25/2020		4,498	
26	152481107	BRUNSWICK 1107	Dx	NEVADA	10/9/2019	2,703	2,442	
					10/23/2019		2,659	
					10/26/2019		2,657	

TABLE 9-2:
LIST OF FREQUENTLY DE-ENERGIZED CIRCUITS
(CONTINUED)

Entry Number	ID of Circuit	Circuit Name	Transmission (Tx)/ Distribution (Dx)	County	Dates of Outages	Number of Customers Served by Circuit (as of December 1, 2022)	Number of Customers Affected	Measures Taken, or Planned to Be Taken, to Reduce the Need for and Impact of Future PSPS of Circuit
					9/7/2020 10/25/2020		2,650 2,672	• 1 Sectionalizing device added or replaced • 1 MSO device replaced • Mitigated by PSPS protocols • Temporary Generation deployed that benefited 4184 customers
27	152481110	BRUNSWICK 1110	Dx	NEVADA	10/9/2019 10/23/2019 10/26/2019 9/7/2020 10/25/2020	3,118	3,307 3,309 3,074 3,048 3,075	• 2 Sectionalizing devices added or replaced • 0.03-line miles undergrounded • Mitigated by PSPS protocols • Temporary Generation deployed that benefited 4184 customers
28	102211101	BUCKS CREEK 1101	Dx	PLUMAS	9/25/2019 10/5/2019	Circuit no longer active	3 4	

TABLE 9-2:
LIST OF FREQUENTLY DE-ENERGIZED CIRCUITS
(CONTINUED)

Entry Number	ID of Circuit	Circuit Name	Transmission (Tx)/ Distribution (Dx)	County	Dates of Outages	Number of Customers Served by Circuit (as of December 1, 2022)	Number of Customers Affected	Measures Taken, or Planned to Be Taken, to Reduce the Need for and Impact of Future PSPS of Circuit
					10/9/2019		4	
					10/26/2019		4	
					9/7/2020		4	
					9/27/2020		4	
					10/14/2020		4	
					10/21/2020		4	
					10/25/2020		4	
29	102211102	BUCKS CREEK 1102	Dx	PLUMAS	10/9/2019		124	
					10/26/2019		123	
					9/7/2020		120	
					9/27/2020		120	
					10/21/2020		119	
					10/25/2020		119	
30	102211103	BUCKS CREEK 1103	Dx	PLUMAS	10/9/2019	322	313	
					10/26/2019		314	
					9/7/2020		311	
					9/27/2020		314	
					10/21/2020		310	
					10/25/2020		311	
					8/17/2021		316	
					10/11/2021		314	

TABLE 9-2:
LIST OF FREQUENTLY DE-ENERGIZED CIRCUITS
(CONTINUED)

Entry Number	ID of Circuit	Circuit Name	Transmission (Tx)/ Distribution (Dx)	County	Dates of Outages	Number of Customers Served by Circuit (as of December 1, 2022)	Number of Customers Affected	Measures Taken, or Planned to Be Taken, to Reduce the Need for and Impact of Future PSPS of Circuit
31	103081105	BUTTE 1105	Dx	BUTTE	6/8/2019	1,093	190	• 4 Sectionalizing devices added or replaced
					9/25/2019		228	
					10/5/2019		230	
					10/9/2019		1,022	
					10/23/2019		230	
					10/26/2019		230	
					9/7/2020		266	
					9/27/2020		271	
					10/14/2020		244	
					10/21/2020		103	
					10/25/2020		175	
					8/17/2021		53	
32	162211101	CALAVERAS CEMENT 1101	Dx	CALAVERAS	10/9/2019	3,374	3,289	• Mitigated by PSPS protocols
					10/23/2019		750	
					10/26/2019		3,292	
					10/25/2020		1,159	
33	42711101	CALISTOGA 1101	Dx	NAPA	10/14/2018	1,632	1,543	
					9/25/2019		1,077	
					10/9/2019		1,566	
					10/23/2019		1,551	
					10/26/2019		1,551	

TABLE 9-2:
LIST OF FREQUENTLY DE-ENERGIZED CIRCUITS
(CONTINUED)

Entry Number	ID of Circuit	Circuit Name	Transmission (Tx)/ Distribution (Dx)	County	Dates of Outages	Number of Customers Served by Circuit (as of December 1, 2022)	Number of Customers Affected	Measures Taken, or Planned to Be Taken, to Reduce the Need for and Impact of Future PSPS of Circuit
					11/20/2019		1,548	• 6 Sectionalizing devices added or replaced • Temporary Generation deployed that benefited 1576 customers
					9/7/2020		1,549	
					9/27/2020		173	
					10/14/2020		1,224	
					10/25/2020		1,219	
					8/17/2021		1,603	
					10/11/2021		88	
34	42711102	CALISTOGA 1102	Dx	NAPA	10/14/2018	2,073	2,073	• 6 Sectionalizing devices added or replaced • 1 MSO device replaced • 0.1 miles of overhead hardening completed • Temporary Generation deployed that benefited 1580 customers
					10/9/2019		2,117	
					10/23/2019		2,116	
					10/26/2019		2,115	
					11/20/2019		2,113	
					9/7/2020		919	
					10/14/2020		608	
					10/25/2020		753	
					8/17/2021		2,076	
35	255451102	CALWATER 1102	Dx	KERN	10/9/2019	2,485	2,357	• Mitigated by PSPS protocols
					10/23/2019		13	
					10/26/2019		13	

**TABLE 9-2:
LIST OF FREQUENTLY DE-ENERGIZED CIRCUITS
(CONTINUED)**

Entry Number	ID of Circuit	Circuit Name	Transmission (Tx)/ Distribution (Dx)	County	Dates of Outages	Number of Customers Served by Circuit (as of December 1, 2022)	Number of Customers Affected	Measures Taken, or Planned to Be Taken, to Reduce the Need for and Impact of Future PSPS of Circuit
					9/7/2020		13	
					12/3/2020		13	
					1/18/2021		13	
					10/14/2021		13	
36	103321101	CEDAR CREEK 1101	Dx	SHASTA	10/9/2019	708	733	
					10/26/2019		732	
					11/20/2019		490	
					9/7/2020		731	
					10/14/2020		731	
					10/21/2020		733	
					10/25/2020		733	
					8/17/2021		721	
37	103201101	CHALLENGE 1101	Dx	PLUMAS	10/9/2019	671	672	
					10/23/2019		670	
					10/26/2019		671	
					9/7/2020		668	
					9/27/2020		666	
					10/14/2020		669	
					10/25/2020		669	
38	103201102	CHALLENGE 1102	Dx	YUBA	9/23/2019	829	819	

TABLE 9-2:
LIST OF FREQUENTLY DE-ENERGIZED CIRCUITS
(CONTINUED)

Entry Number	ID of Circuit	Circuit Name	Transmission (Tx)/ Distribution (Dx)	County	Dates of Outages	Number of Customers Served by Circuit (as of December 1, 2022)	Number of Customers Affected	Measures Taken, or Planned to Be Taken, to Reduce the Need for and Impact of Future PSPS of Circuit
					9/25/2019		817	
					10/9/2019		821	
					10/23/2019		822	
					10/26/2019		822	
					9/7/2020		827	
					9/27/2020		826	
					10/14/2020		404	
					10/25/2020		829	
39	103091101	CLARK ROAD 1101	Dx	BUTTE	6/8/2019	14	13	
					9/25/2019		14	
					10/5/2019		15	
					10/9/2019		15	
					10/23/2019		15	
					10/26/2019		15	
40	103091102	CLARK ROAD 1102	Dx	BUTTE	6/8/2019	1,128	1,039	• 4 Sectionalizing devices added or replaced
					9/25/2019		1,056	
					10/5/2019		1,053	
					10/9/2019		1,055	
					10/23/2019		1,056	
					10/26/2019		1,054	
					9/7/2020		1,093	

TABLE 9-2:
LIST OF FREQUENTLY DE-ENERGIZED CIRCUITS
(CONTINUED)

Entry Number	ID of Circuit	Circuit Name	Transmission (Tx)/ Distribution (Dx)	County	Dates of Outages	Number of Customers Served by Circuit (as of December 1, 2022)	Number of Customers Affected	Measures Taken, or Planned to Be Taken, to Reduce the Need for and Impact of Future PSPS of Circuit
					9/27/2020		663	
					10/14/2020		839	
					10/21/2020		838	
					10/25/2020		672	
					8/17/2021		490	
					10/11/2021		480	
41	42821102	CLOVERDALE 1102	Dx	SONOMA	10/9/2019	2,537	2,543	• 2 Sectionalizing devices added or replaced • 1 MSO device replaced • 1 MSO device installations or replacement planned
					10/23/2019		919	
					10/26/2019		2,527	
					11/20/2019		15	
					10/14/2020		39	
					10/25/2020		252	
					8/17/2021		70	
					10/11/2021		38	
42	152471101	COLUMBIA HILL 1101	Dx	NEVADA	10/9/2019	1,128	1,121	• 0.3 miles of overhead hardening completed
					10/23/2019		1,121	
					10/26/2019		976	
					9/7/2020		1,126	
					9/27/2020		229	
					10/14/2020		18	
					10/25/2020		1,126	

TABLE 9-2:
LIST OF FREQUENTLY DE-ENERGIZED CIRCUITS
(CONTINUED)

Entry Number	ID of Circuit	Circuit Name	Transmission (Tx)/ Distribution (Dx)	County	Dates of Outages	Number of Customers Served by Circuit (as of December 1, 2022)	Number of Customers Affected	Measures Taken, or Planned to Be Taken, to Reduce the Need for and Impact of Future PSPS of Circuit
43	103331101	CORNING 1101	Dx	TEHAMA	10/9/2019	2,079	884	• 1 Sectionalizing device added or replaced
					10/26/2019		881	
					10/25/2020		822	
					8/17/2021		840	
					9/20/2021		841	
					10/11/2021		895	
44	103331102	CORNING 1102	Dx	TEHAMA	10/9/2019	1,604	293	• Temporary Generation deployed that benefited 1 customer
					10/26/2019		294	
					10/21/2020		291	
					10/25/2020		292	
					8/17/2021		286	
					9/20/2021		291	
					10/11/2021		292	
45	63121101	CORTINA 1101	Dx	COLUSA	10/9/2019	315	311	• 2 Sectionalizing devices added or replaced • Temporary Generation deployed that benefited 1 customer
					10/26/2019		8	
					11/20/2019		8	
					10/25/2020		8	
					8/17/2021		8	
					9/20/2021		8	
					10/11/2021		8	
46	102931103		Dx	TEHAMA	10/9/2019	2,754	2,473	

TABLE 9-2:
LIST OF FREQUENTLY DE-ENERGIZED CIRCUITS
(CONTINUED)

Entry Number	ID of Circuit	Circuit Name	Transmission (Tx)/ Distribution (Dx)	County	Dates of Outages	Number of Customers Served by Circuit (as of December 1, 2022)	Number of Customers Affected	Measures Taken, or Planned to Be Taken, to Reduce the Need for and Impact of Future PSPS of Circuit
		COTTONWOOD 1103			10/26/2019		2,704	• 3 Sectionalizing devices added or replaced
					11/20/2019		1,490	
					10/25/2020		2,419	
					8/17/2021		2,435	
					10/11/2021		683	
47	103351101	DESCHUTES 1101	Dx	SHASTA	10/9/2019	1,168	1,160	
					10/26/2019		1,162	
					11/20/2019		904	
					9/7/2020		24	
					9/27/2020		170	
					10/14/2020		295	
					10/21/2020		1,168	
					10/25/2020		1,171	
					8/17/2021		253	
					10/11/2021		74	
48	103351104	DESCHUTES 1104	Dx	SHASTA	10/9/2019	2,143	2,360	
					10/26/2019		2,362	
					11/20/2019		491	
					10/21/2020		2,366	
					10/25/2020		2,372	
					8/17/2021		389	

TABLE 9-2:
LIST OF FREQUENTLY DE-ENERGIZED CIRCUITS
(CONTINUED)

Entry Number	ID of Circuit	Circuit Name	Transmission (Tx)/ Distribution (Dx)	County	Dates of Outages	Number of Customers Served by Circuit (as of December 1, 2022)	Number of Customers Affected	Measures Taken, or Planned to Be Taken, to Reduce the Need for and Impact of Future PSPS of Circuit
					10/11/2021		88	• 7 Sectionalizing devices added or replaced • 37.1 miles of overhead hardening completed • 0.2 line miles undergrounded
49	152261103	DIAMOND SPRINGS 1103	Dx	EL DORADO	10/14/2018	2,442	2,182	• 3 Sectionalizing devices added or replaced • Mitigated by PSPS protocols
					10/9/2019		1,464	
					10/23/2019		1,496	
					10/26/2019		1,995	
					9/27/2020		677	
					10/25/2020		1,495	
50	152261104	DIAMOND SPRINGS 1104	Dx	EL DORADO	10/14/2018	1,010	1,001	• 1 MSO device replaced • Mitigated by PSPS protocols
					10/9/2019		583	
					10/23/2019		466	
					10/26/2019		586	
					10/25/2020		463	
51	152261105	DIAMOND SPRINGS 1105	Dx	EL DORADO	10/9/2019	2,480	2,460	
					10/23/2019		2,459	
					10/26/2019		2,459	

TABLE 9-2:
LIST OF FREQUENTLY DE-ENERGIZED CIRCUITS
(CONTINUED)

Entry Number	ID of Circuit	Circuit Name	Transmission (Tx)/ Distribution (Dx)	County	Dates of Outages	Number of Customers Served by Circuit (as of December 1, 2022)	Number of Customers Affected	Measures Taken, or Planned to Be Taken, to Reduce the Need for and Impact of Future PSPS of Circuit
					10/25/2020		2,464	• 0.4 miles of overhead hardening completed • Mitigated by PSPS protocols
52	152261106	DIAMOND SPRINGS 1106	Dx	EL DORADO	10/9/2019	3,172	2,334	• 5 Sectionalizing devices added or replaced • 0.1 miles of overhead hardening completed • 1.3 line miles undergrounded • Mitigated by PSPS protocols
					10/23/2019		2,337	
					10/26/2019		2,336	
					9/7/2020		68	
					9/27/2020		1,678	
					10/25/2020		2,349	
53	152261107	DIAMOND SPRINGS 1107	Dx	EL DORADO	10/14/2018	1,799	1,795	
					10/9/2019		1,294	
					10/23/2019		1,294	
					10/26/2019		1,294	

TABLE 9-2:
LIST OF FREQUENTLY DE-ENERGIZED CIRCUITS
(CONTINUED)

Entry Number	ID of Circuit	Circuit Name	Transmission (Tx)/ Distribution (Dx)	County	Dates of Outages	Number of Customers Served by Circuit (as of December 1, 2022)	Number of Customers Affected	Measures Taken, or Planned to Be Taken, to Reduce the Need for and Impact of Future PSPS of Circuit
					10/25/2020		1,286	• 3 Sectionalizing devices added or replaced • 7.4 miles of overhead hardening completed • 1 line miles undergrounded • Mitigated by PSPS protocols
54	153741101	DOBBINS 1101	Dx	YUBA	9/23/2019 9/25/2019 10/9/2019 10/23/2019 10/26/2019 9/7/2020 9/27/2020 10/14/2020 10/25/2020	867	847 846 846 845 845 857 478 668 861	• 1 Sectionalizing device added or replaced
55	152321101	DRUM 1101	Dx	PLACER	10/9/2019 10/23/2019 10/26/2019	193	191 191 191	

TABLE 9-2:
LIST OF FREQUENTLY DE-ENERGIZED CIRCUITS
(CONTINUED)

Entry Number	ID of Circuit	Circuit Name	Transmission (Tx)/ Distribution (Dx)	County	Dates of Outages	Number of Customers Served by Circuit (as of December 1, 2022)	Number of Customers Affected	Measures Taken, or Planned to Be Taken, to Reduce the Need for and Impact of Future PSPS of Circuit
					9/7/2020		188	
					9/27/2020		191	
					10/25/2020		192	
56	43071101	DUNBAR 1101	Dx	SONOMA	10/9/2019	2,351	3,205	• 11 Sectionalizing devices added or replaced • 0.4 miles of overhead hardening completed
					10/23/2019		2,649	
					10/26/2019		3,213	
					11/20/2019		136	
					9/7/2020		2,528	
					10/14/2020		201	
					10/25/2020		3,191	
					8/17/2021		131	
57	43071103	DUNBAR 1103	Dx	SONOMA	10/9/2019	3,210	2,340	• 11 Sectionalizing devices added or replaced
					10/23/2019		291	
					10/26/2019		2,339	
					11/20/2019		148	
					9/7/2020		272	
					10/14/2020		308	
					10/25/2020		946	
					8/17/2021		253	
58	152762101	EL DORADO PH 2101	Dx	EL DORADO	10/14/2018	3,811	4,096	
					10/9/2019		4,543	

TABLE 9-2:
LIST OF FREQUENTLY DE-ENERGIZED CIRCUITS
(CONTINUED)

Entry Number	ID of Circuit	Circuit Name	Transmission (Tx)/ Distribution (Dx)	County	Dates of Outages	Number of Customers Served by Circuit (as of December 1, 2022)	Number of Customers Affected	Measures Taken, or Planned to Be Taken, to Reduce the Need for and Impact of Future PSPS of Circuit
					10/23/2019		4,560	• 1 MSO device replaced • 45 miles of overhead hardening completed • 12.8 line miles undergrounded
					10/26/2019		4,539	
					9/7/2020		4,552	
					9/27/2020		4,570	
					10/14/2020		438	
					10/25/2020		4,572	
59	152762102	EL DORADO PH 2102	Dx	EL DORADO	10/14/2018	1,607	1,592	• 14.7 miles of overhead hardening completed
					10/9/2019		1,592	
					10/23/2019		1,592	
					10/26/2019		1,593	
					9/7/2020		1,581	
					9/27/2020		1,587	
					10/25/2020		1,599	
60	162161101	ELECTRA 1101	Dx	AMADOR	10/9/2019	1,883	1,879	• 4 Sectionalizing devices added or replaced • Mitigated by PSPS protocols
					10/23/2019		1,878	
					10/26/2019		1,879	
					10/25/2020		1,342	
61	42751113	FITCH MOUNTAIN 1113	Dx	SONOMA	10/9/2019	2,241	2,314	
					10/23/2019		545	

TABLE 9-2:
LIST OF FREQUENTLY DE-ENERGIZED CIRCUITS
(CONTINUED)

Entry Number	ID of Circuit	Circuit Name	Transmission (Tx)/ Distribution (Dx)	County	Dates of Outages	Number of Customers Served by Circuit (as of December 1, 2022)	Number of Customers Affected	Measures Taken, or Planned to Be Taken, to Reduce the Need for and Impact of Future PSPS of Circuit
					10/26/2019		2,314	• 4 Sectionalizing devices added or replaced • 5.1 miles of overhead hardening completed • Mitigated by PSPS protocols
					10/25/2020		568	
62	152181101	FORESTHILL 1101	Dx	PLACER	10/14/2018	2,246	2,198	
					9/25/2019		2,210	
					10/9/2019		2,213	
					10/23/2019		2,214	
					10/26/2019		2,212	
					9/7/2020		2,206	
					9/27/2020		2,219	
					10/25/2020		2,220	
63	152181102	FORESTHILL 1102	Dx	PLACER	10/14/2018	425	417	
					9/25/2019		421	
					10/9/2019		420	
					10/23/2019		421	
					10/26/2019		421	
					9/7/2020		420	

TABLE 9-2:
LIST OF FREQUENTLY DE-ENERGIZED CIRCUITS
(CONTINUED)

Entry Number	ID of Circuit	Circuit Name	Transmission (Tx)/ Distribution (Dx)	County	Dates of Outages	Number of Customers Served by Circuit (as of December 1, 2022)	Number of Customers Affected	Measures Taken, or Planned to Be Taken, to Reduce the Need for and Impact of Future PSPS of Circuit
					9/27/2020 10/25/2020		421 421	
64	192321122	FORT SEWARD 1122	Dx	HUMBOLDT	10/9/2019 10/26/2019 9/7/2020 10/14/2020 10/25/2020	89	91 91 89 47 89	• 1 Sectionalizing device added or replaced • Mitigated by PSPS protocols
65	163451701	FROGTOWN 1701	Dx	CALAVERAS	10/9/2019 10/23/2019 10/26/2019 9/7/2020 10/25/2020	1,986	1,914 1,740 1,916 1,251 1,926	• 0.6 miles of overhead hardening completed • Mitigated by PSPS protocols
66	42561102	FULTON 1102	Dx	SONOMA	10/9/2019 10/23/2019 10/26/2019 10/25/2020	2,250	942 861 578 315	• 2 Sectionalizing devices added or replaced • 1 MSO device replaced • 1 MSO device installations or replacement planned • Mitigated by PSPS protocols

TABLE 9-2:
LIST OF FREQUENTLY DE-ENERGIZED CIRCUITS
(CONTINUED)

Entry Number	ID of Circuit	Circuit Name	Transmission (Tx)/ Distribution (Dx)	County	Dates of Outages	Number of Customers Served by Circuit (as of December 1, 2022)	Number of Customers Affected	Measures Taken, or Planned to Be Taken, to Reduce the Need for and Impact of Future PSPS of Circuit
67	42561107	FULTON 1107	Dx	SONOMA	9/25/2019	3,134	168	• 2 Sectionalizing devices added or replaced • 1 MSO device replaced • 4.2 miles of overhead hardening completed • 2.4 line miles undergrounded • Mitigated by PSPS protocols
					10/9/2019		843	
					10/23/2019		736	
					10/26/2019		848	
					11/20/2019		378	
					10/25/2020		372	
68	42891101	GEYSERVILLE 1101	Dx	SONOMA	10/9/2019	1,438	1,445	• 4 Sectionalizing devices added or replaced • 1 MSO device replaced • Mitigated by PSPS protocols
					10/23/2019		1,113	
					10/26/2019		1,446	
					10/25/2020		89	
					8/17/2021		26	
69	42891102	GEYSERVILLE 1102	Dx	SONOMA	10/9/2019	1,142	1,173	
					10/23/2019		787	
					10/26/2019		396	
					10/14/2020		57	
					10/25/2020		535	

TABLE 9-2:
LIST OF FREQUENTLY DE-ENERGIZED CIRCUITS
(CONTINUED)

Entry Number	ID of Circuit	Circuit Name	Transmission (Tx)/ Distribution (Dx)	County	Dates of Outages	Number of Customers Served by Circuit (as of December 1, 2022)	Number of Customers Affected	Measures Taken, or Planned to Be Taken, to Reduce the Need for and Impact of Future PSPS of Circuit
					8/17/2021		297	• 13 Sectionalizing devices added or replaced • Temporary Generation deployed that benefited 2 customers
					10/11/2021		28	
70	103401101	GIRVAN 1101	Dx	SHASTA	10/9/2019	1,219	1,264	
					10/26/2019		1,264	
					11/20/2019		1,266	
					10/21/2020		1,173	
					10/25/2020		1,187	
					8/17/2021		1,207	
					10/11/2021		1,090	
71	102601101	GLENN 1101	Dx	GLENN	10/9/2019	1,778	47	
					10/26/2019		47	
					11/20/2019		5	
					10/25/2020		5	
					8/17/2021		5	
					9/20/2021		5	
					10/11/2021		5	
72	152031101		Dx	NEVADA	10/9/2019	797	745	

TABLE 9-2:
LIST OF FREQUENTLY DE-ENERGIZED CIRCUITS
(CONTINUED)

Entry Number	ID of Circuit	Circuit Name	Transmission (Tx)/ Distribution (Dx)	County	Dates of Outages	Number of Customers Served by Circuit (as of December 1, 2022)	Number of Customers Affected	Measures Taken, or Planned to Be Taken, to Reduce the Need for and Impact of Future PSPS of Circuit
		GRASS VALLEY 1101			10/23/2019 10/26/2019 10/25/2020		746 726 331	• 2 Sectionalizing devices added or replaced • Mitigated by PSPS protocols
73	152031103	GRASS VALLEY 1103	Dx	NEVADA	10/9/2019 10/23/2019 10/26/2019 10/25/2020	1,459	1,451 1,449 1,448 1,446	• Mitigated by PSPS protocols
74	24101103	HALF MOON BAY 1103	Dx	SAN MATEO	10/9/2019 10/23/2019 10/26/2019 10/14/2020 10/25/2020	4,856	4,863 651 4,866 730 1,936	• 10 Sectionalizing devices added or replaced • 2.5 line miles undergrounded
75	152241101	HALSEY 1101	Dx	PLACER	10/9/2019 10/23/2019 10/26/2019 10/25/2020	2,347	2,257 1,671 2,259 2,283	• Mitigated by PSPS protocols
76	152241102	HALSEY 1102	Dx	PLACER	10/9/2019 10/23/2019	1,889	2,057 873	

TABLE 9-2:
LIST OF FREQUENTLY DE-ENERGIZED CIRCUITS
(CONTINUED)

Entry Number	ID of Circuit	Circuit Name	Transmission (Tx)/ Distribution (Dx)	County	Dates of Outages	Number of Customers Served by Circuit (as of December 1, 2022)	Number of Customers Affected	Measures Taken, or Planned to Be Taken, to Reduce the Need for and Impact of Future PSPS of Circuit
					10/26/2019		2,058	• 7 Sectionalizing devices added or replaced • Mitigated by PSPS protocols
					10/25/2020		2,059	
77	152691103	HIGGINS 1103	Dx	NEVADA	10/9/2019	2,823	1,931	• 1 Sectionalizing device added or replaced • Mitigated by PSPS protocols
					10/23/2019		1,934	
					10/26/2019		1,935	
					10/25/2020		1,914	
78	152691104	HIGGINS 1104	Dx	NEVADA	10/9/2019	3,074	2,706	• Mitigated by PSPS protocols
					10/23/2019		2,707	
					10/26/2019		2,699	
					10/25/2020		2,709	
79	152691107	HIGGINS 1107	Dx	NEVADA	10/9/2019	1,694	1,678	• Mitigated by PSPS protocols
					10/23/2019		1,678	
					10/26/2019		1,678	
					10/25/2020		1,685	
80	152691109	HIGGINS 1109	Dx	NEVADA	10/9/2019	1,057	1,613	
					10/23/2019		1,617	
					10/26/2019		1,616	

TABLE 9-2:
LIST OF FREQUENTLY DE-ENERGIZED CIRCUITS
(CONTINUED)

Entry Number	ID of Circuit	Circuit Name	Transmission (Tx)/ Distribution (Dx)	County	Dates of Outages	Number of Customers Served by Circuit (as of December 1, 2022)	Number of Customers Affected	Measures Taken, or Planned to Be Taken, to Reduce the Need for and Impact of Future PSPS of Circuit
					10/25/2020		1,609	• 1 Sectionalizing device added or replaced • 0.1 line miles undergrounded • Mitigated by PSPS protocols
81	152691110	HIGGINS 1110	Dx	NEVADA	10/9/2019 10/23/2019 10/26/2019 10/25/2020	1,371	1,357 1,358 1,358 972	• 3 Sectionalizing devices added or replaced • Mitigated by PSPS protocols
82	43361102	HIGHLANDS 1102	Dx	LAKE	10/14/2018 10/9/2019 10/26/2019 11/20/2019 10/25/2020 8/17/2021 10/11/2021	3,386	22 3,391 3,395 3,399 24 10 15	• 6 Sectionalizing devices added or replaced • 1.5 miles of overhead hardening completed • Mitigated by PSPS protocols
83	43361103	HIGHLANDS 1103	Dx	LAKE	10/9/2019 10/26/2019 11/20/2019 10/14/2020	2,387	2,416 2,418 2,426 52	

TABLE 9-2:
LIST OF FREQUENTLY DE-ENERGIZED CIRCUITS
(CONTINUED)

Entry Number	ID of Circuit	Circuit Name	Transmission (Tx)/ Distribution (Dx)	County	Dates of Outages	Number of Customers Served by Circuit (as of December 1, 2022)	Number of Customers Affected	Measures Taken, or Planned to Be Taken, to Reduce the Need for and Impact of Future PSPS of Circuit
					10/25/2020 8/17/2021 9/20/2021 10/11/2021		1,926 1,325 51 1,032	• 2 Sectionalizing devices added or replaced • Temporary Generation deployed that benefited 1 customer
84	43361104	HIGHLANDS 1104	Dx	LAKE	10/9/2019 10/26/2019 11/20/2019 10/25/2020	2,742	2,718 2,714 2,710 23	• Mitigated by PSPS protocols • Temporary Generation deployed that benefited 4 customers
85	42251101	HOPLAND 1101	Dx	MENDOCINO	10/9/2019 10/23/2019 10/26/2019 11/20/2019 10/25/2020	1,255	1,245 162 1,246 162 58	• Mitigated by PSPS protocols
86	103441101	JESSUP 1101	Dx	SHASTA	10/9/2019 10/26/2019 11/20/2019 10/21/2020 10/25/2020	1,953	1,941 1,946 1,710 1,527 1,526	• 3 Sectionalizing devices added or replaced

TABLE 9-2:
LIST OF FREQUENTLY DE-ENERGIZED CIRCUITS
(CONTINUED)

Entry Number	ID of Circuit	Circuit Name	Transmission (Tx)/ Distribution (Dx)	County	Dates of Outages	Number of Customers Served by Circuit (as of December 1, 2022)	Number of Customers Affected	Measures Taken, or Planned to Be Taken, to Reduce the Need for and Impact of Future PSPS of Circuit
					8/17/2021		1,459	
87	103441102	JESSUP 1102	Dx	SHASTA	10/9/2019	2,260	2,232	• 2 Sectionalizing devices added or replaced
					10/26/2019		2,236	
					11/20/2019		1,520	
					10/21/2020		1,487	
					10/25/2020		1,549	
					8/17/2021		1,504	
					10/11/2021		199	
88	103441103	JESSUP 1103	Dx	SHASTA	10/9/2019	1,581	1,560	• 2 Sectionalizing devices added or replaced
					10/26/2019		1,561	
					11/20/2019		360	
					10/21/2020		145	
					10/25/2020		159	
					8/17/2021		113	
89	103221101	KANAKA 1101	Dx	BUTTE	9/23/2019	468	609	• 7.7 miles of overhead hardening completed • 2.9 line miles undergrounded
					9/25/2019		609	
					10/5/2019		609	
					10/9/2019		609	
					10/23/2019		607	
					10/26/2019		604	
					11/20/2019		41	

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LIST OF FREQUENTLY DE-ENERGIZED CIRCUITS
(CONTINUED)

Entry Number	ID of Circuit	Circuit Name	Transmission (Tx)/ Distribution (Dx)	County	Dates of Outages	Number of Customers Served by Circuit (as of December 1, 2022)	Number of Customers Affected	Measures Taken, or Planned to Be Taken, to Reduce the Need for and Impact of Future PSPS of Circuit
					9/7/2020		581	
					10/14/2020		354	
					10/25/2020		367	
					10/11/2021		9	
90	253911102	LAMONT 1102	Dx	KERN	10/9/2019	456	5	• 1 MSO device replaced
					10/23/2019		5	
					10/26/2019		5	
					9/7/2020		5	
					12/3/2020		5	
					1/18/2021		5	
					10/11/2021		5	
91	153701104	LINCOLN 1104	Dx	PLACER	10/9/2019	1,307	1,240	• 1 Sectionalizing device added or replaced • 1 MSO device replaced • Mitigated by PSPS protocols
					10/23/2019		217	
					10/26/2019		672	
92	103142102	LOGAN CREEK 2102	Dx	GLENN	10/9/2019	1,372	1,369	• 1 Sectionalizing device added or replaced
					10/26/2019		9	
					11/20/2019		9	
					10/25/2020		9	

TABLE 9-2:
LIST OF FREQUENTLY DE-ENERGIZED CIRCUITS
(CONTINUED)

Entry Number	ID of Circuit	Circuit Name	Transmission (Tx)/ Distribution (Dx)	County	Dates of Outages	Number of Customers Served by Circuit (as of December 1, 2022)	Number of Customers Affected	Measures Taken, or Planned to Be Taken, to Reduce the Need for and Impact of Future PSPS of Circuit
					8/17/2021		8	
					10/11/2021		8	
93	192411101	LOW GAP 1101	Dx	TRINITY	10/9/2019	607	693	• 1 Sectionalizing device added or replaced
					10/26/2019		692	
					9/7/2020		700	
					10/14/2020		225	
					10/25/2020		670	
94	43351103	LUCERNE 1103	Dx	LAKE	10/9/2019	2,116	2,108	• 2 Sectionalizing devices added or replaced • Mitigated by PSPS protocols
					10/23/2019		1	
					10/26/2019		2,111	
					10/25/2020		2,128	
95	63172101	MADISON 2101	Dx	YOLO	10/9/2019	1,971	1,943	• 9 Sectionalizing devices added or replaced • 2 MSO device replaced • 1 MSO device installations or replacement planned
					10/26/2019		1,944	
					11/20/2019		341	
					10/14/2020		10	
					10/21/2020		10	
					10/25/2020		10	
					8/17/2021		222	
					9/20/2021		10	
					10/11/2021		242	

TABLE 9-2:
LIST OF FREQUENTLY DE-ENERGIZED CIRCUITS
(CONTINUED)

Entry Number	ID of Circuit	Circuit Name	Transmission (Tx)/ Distribution (Dx)	County	Dates of Outages	Number of Customers Served by Circuit (as of December 1, 2022)	Number of Customers Affected	Measures Taken, or Planned to Be Taken, to Reduce the Need for and Impact of Future PSPS of Circuit
96	163011101	MARTELL 1101	Dx	AMADOR	10/9/2019	2,254	2,234	• 10 Sectionalizing devices added or replaced • 0.5 line miles undergrounded • Mitigated by PSPS protocols
					10/23/2019		634	
					10/26/2019		2,236	
					10/25/2020		475	
97	62881105	MAXWELL 1105	Dx	COLUSA	10/9/2019	798	43	
					10/26/2019		43	
					10/25/2020		44	
					8/17/2021		44	
					9/20/2021		44	
					10/11/2021		44	
98	43141101	MIDDLETOWN 1101	Dx	LAKE	10/14/2018	1,981	1,862	
					10/9/2019		1,905	
					10/23/2019		1,339	
					10/26/2019		1,917	
					11/20/2019		1,907	
					9/7/2020		82	
					9/27/2020		113	
					10/14/2020		54	
					10/25/2020		1,936	

TABLE 9-2:
LIST OF FREQUENTLY DE-ENERGIZED CIRCUITS
(CONTINUED)

Entry Number	ID of Circuit	Circuit Name	Transmission (Tx)/ Distribution (Dx)	County	Dates of Outages	Number of Customers Served by Circuit (as of December 1, 2022)	Number of Customers Affected	Measures Taken, or Planned to Be Taken, to Reduce the Need for and Impact of Future PSPS of Circuit
					8/17/2021		1,216	• 8 Sectionalizing devices added or replaced • 14.1 miles of overhead hardening completed • 3.2 line miles undergrounded • Temporary Generation deployed that benefited 1 customer
					10/11/2021		487	
99	43141102	MIDDLETOWN 1102	Dx	LAKE	10/14/2018	2,331	2,293	
					10/9/2019		2,298	
					10/26/2019		2,296	
					11/20/2019		1,817	
					10/25/2020		2,313	
					8/17/2021		691	

TABLE 9-2:
LIST OF FREQUENTLY DE-ENERGIZED CIRCUITS
(CONTINUED)

Entry Number	ID of Circuit	Circuit Name	Transmission (Tx)/ Distribution (Dx)	County	Dates of Outages	Number of Customers Served by Circuit (as of December 1, 2022)	Number of Customers Affected	Measures Taken, or Planned to Be Taken, to Reduce the Need for and Impact of Future PSPS of Circuit
					10/11/2021		2,301	• 1 Sectionalizing device added or replaced • 1.1 miles of overhead hardening completed • 0.6 line miles undergrounded • Mitigated by PSPS protocols • Temporary Generation deployed that benefited 6 customers
100	43141103	MIDDLETOWN 1103	Dx	LAKE	10/14/2018	142	146	• 7 miles of overhead hardening completed • 6.9 line miles undergrounded • Mitigated by PSPS protocols
					10/9/2019		145	
					10/26/2019		145	
					11/20/2019		145	
					10/25/2020		143	
					10/11/2021		5	
101	43302103	MONROE 2103	Dx	SONOMA	10/9/2019	4,206	202	• Mitigated by PSPS protocols
					10/23/2019		10	

TABLE 9-2:
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(CONTINUED)

Entry Number	ID of Circuit	Circuit Name	Transmission (Tx)/ Distribution (Dx)	County	Dates of Outages	Number of Customers Served by Circuit (as of December 1, 2022)	Number of Customers Affected	Measures Taken, or Planned to Be Taken, to Reduce the Need for and Impact of Future PSPS of Circuit
					10/26/2019		10	
102	43302107	MONROE 2107	Dx	SONOMA	10/9/2019	2,651	2,634	• Mitigated by PSPS protocols
					10/23/2019		106	
					10/26/2019		106	
103	43051101	MONTICELLO 1101	Dx	NAPA	6/8/2019	1,163	1,330	• 2 Sectionalizing devices added or replaced
					9/25/2019		18	
					10/9/2019		1,331	
					10/23/2019		28	
					10/26/2019		1,324	
					11/20/2019		1,334	
					10/14/2020		444	
					10/25/2020		1,100	
					8/17/2021		932	
					9/20/2021		8	
					10/11/2021		1,133	
104	152282101	MOUNTAIN QUARRIES 2101	Dx	EL DORADO	10/14/2018	3,632	595	
					10/9/2019		3,613	
					10/23/2019		2,447	
					10/26/2019		3,498	
					9/7/2020		1,774	
					9/27/2020		282	

TABLE 9-2:
LIST OF FREQUENTLY DE-ENERGIZED CIRCUITS
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Entry Number	ID of Circuit	Circuit Name	Transmission (Tx)/ Distribution (Dx)	County	Dates of Outages	Number of Customers Served by Circuit (as of December 1, 2022)	Number of Customers Affected	Measures Taken, or Planned to Be Taken, to Reduce the Need for and Impact of Future PSPS of Circuit
					10/25/2020		3,613	• 1.8 miles of overhead hardening completed • 3.3 line miles undergrounded • Mitigated by PSPS protocols
105	153132101	NARROWS 2101	Dx	YUBA	9/23/2019	518	503	
					9/25/2019		503	
					10/9/2019		504	
					10/23/2019		504	
					10/26/2019		504	
					10/25/2020		264	
106	153132102	NARROWS 2102	Dx	NEVADA	9/23/2019	3,412	3,392	• Mitigated by PSPS protocols
					9/25/2019		3,392	
					10/9/2019		3,387	
					10/23/2019		3,388	
					10/26/2019		3,387	
					10/25/2020		3,395	
107	153132105	NARROWS 2105	Dx	NEVADA	9/23/2019	3,963	3,904	• Mitigated by PSPS protocols
					9/25/2019		3,904	
					10/9/2019		3,903	

TABLE 9-2:
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Entry Number	ID of Circuit	Circuit Name	Transmission (Tx)/ Distribution (Dx)	County	Dates of Outages	Number of Customers Served by Circuit (as of December 1, 2022)	Number of Customers Affected	Measures Taken, or Planned to Be Taken, to Reduce the Need for and Impact of Future PSPS of Circuit
					10/23/2019		3,901	
					10/26/2019		3,901	
					10/25/2020		3,913	
108	102041104	NOTRE DAME 1104	Dx	BUTTE	6/8/2019	2,555	223	• 1 Sectionalizing device added or replaced • Mitigated by PSPS protocols
					9/25/2019		217	
					10/5/2019		303	
					10/9/2019		2,265	
					10/23/2019		217	
					10/26/2019		217	
					9/7/2020		226	
					9/27/2020		221	
					10/14/2020		218	
					10/25/2020		211	
109	163541102	OLETA 1102	Dx	AMADOR	10/14/2018	1,092	49	• 3 Sectionalizing devices added or replaced • Mitigated by PSPS protocols
					10/9/2019		1,056	
					10/23/2019		500	
					10/26/2019		1,058	
110	103521103	OREGON TRAIL 1103	Dx	SHASTA	10/9/2019	1,757	1,706	
					10/26/2019		1,708	
					11/20/2019		138	
					10/14/2020		236	

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LIST OF FREQUENTLY DE-ENERGIZED CIRCUITS
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Entry Number	ID of Circuit	Circuit Name	Transmission (Tx)/ Distribution (Dx)	County	Dates of Outages	Number of Customers Served by Circuit (as of December 1, 2022)	Number of Customers Affected	Measures Taken, or Planned to Be Taken, to Reduce the Need for and Impact of Future PSPS of Circuit
					10/21/2020		1,734	• 21.5 miles of overhead hardening completed • 7.7 line miles undergrounded
					10/25/2020		1,735	
					8/17/2021		1,130	
111	103521104	OREGON TRAIL 1104	Dx	SHASTA	10/9/2019	1,222	958	
					10/26/2019		960	
					11/20/2019		67	
					10/21/2020		952	
					10/25/2020		956	
					8/17/2021		325	
112	103031101	ORO FINO 1101	Dx	BUTTE	6/8/2019	1,829	2,281	
					9/25/2019		2,277	
					10/5/2019		2,277	
					10/9/2019		2,277	
					10/23/2019		2,279	
					10/26/2019		2,280	
					9/7/2020		2,275	
					9/27/2020		2,287	
					10/14/2020		2,290	
					10/21/2020		2,294	

TABLE 9-2:
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(CONTINUED)

Entry Number	ID of Circuit	Circuit Name	Transmission (Tx)/ Distribution (Dx)	County	Dates of Outages	Number of Customers Served by Circuit (as of December 1, 2022)	Number of Customers Affected	Measures Taken, or Planned to Be Taken, to Reduce the Need for and Impact of Future PSPS of Circuit
					10/25/2020		2,284	
					8/17/2021		2,290	
113	103031102	ORO FINO 1102	Dx	BUTTE	6/8/2019	1,966	1,950	• 1 Sectionalizing device added or replaced
					9/25/2019		1,952	
					10/5/2019		1,948	
					10/9/2019		1,949	
					10/23/2019		1,951	
					10/26/2019		1,950	
					9/7/2020		1,968	
					9/27/2020		1,971	
					10/14/2020		1,975	
					10/21/2020		1,974	
					10/25/2020		1,974	
					8/17/2021		1,185	
114	102521104	OROVILLE 1104	Dx	BUTTE	6/8/2019	1,333	1,269	• Mitigated by PSPS protocols
					9/25/2019		1,265	
					10/9/2019		57	
115	103461101	PANORAMA 1101	Dx	SHASTA	10/9/2019	1,474	794	• 1 Sectionalizing device added or replaced • Mitigated by PSPS protocols
					10/26/2019		794	
					11/20/2019		772	
					10/21/2020		1,117	

TABLE 9-2:
LIST OF FREQUENTLY DE-ENERGIZED CIRCUITS
(CONTINUED)

Entry Number	ID of Circuit	Circuit Name	Transmission (Tx)/ Distribution (Dx)	County	Dates of Outages	Number of Customers Served by Circuit (as of December 1, 2022)	Number of Customers Affected	Measures Taken, or Planned to Be Taken, to Reduce the Need for and Impact of Future PSPS of Circuit
					10/25/2020		808	
					8/17/2021		791	
					10/11/2021		791	
116	103461102	PANORAMA 1102	Dx	SHASTA	10/9/2019	2,437	212	• 1 Sectionalizing device added or replaced • Mitigated by PSPS protocols
					10/26/2019		214	
					11/20/2019		215	
					10/14/2020		72	
					10/21/2020		66	
					10/25/2020		92	
					8/17/2021		19	
					10/11/2021		120	
117	102831103	PARADISE 1103	Dx	BUTTE	6/8/2019	1,943	737	• 4 Sectionalizing devices added or replaced • Temporary Generation deployed
					9/25/2019		805	
					10/5/2019		833	
					10/9/2019		839	
					10/23/2019		857	
					10/26/2019		859	
					9/7/2020		62	
					9/27/2020		242	
					10/14/2020		249	
					10/21/2020		249	

TABLE 9-2:
LIST OF FREQUENTLY DE-ENERGIZED CIRCUITS
(CONTINUED)

Entry Number	ID of Circuit	Circuit Name	Transmission (Tx)/ Distribution (Dx)	County	Dates of Outages	Number of Customers Served by Circuit (as of December 1, 2022)	Number of Customers Affected	Measures Taken, or Planned to Be Taken, to Reduce the Need for and Impact of Future PSPS of Circuit
					10/25/2020		508	
118	102831104	PARADISE 1104	Dx	BUTTE	6/8/2019	2,265	670	• 1 Sectionalizing device added or replaced
					9/25/2019		783	
					10/5/2019		791	
					10/9/2019		792	
					10/23/2019		806	
					10/26/2019		830	
					9/7/2020		1,872	
					9/27/2020		1,782	
					10/14/2020		1,900	
					10/21/2020		1,907	
					10/25/2020		1,943	
					8/17/2021		1,301	
119	102831105	PARADISE 1105	Dx	BUTTE	9/25/2019	1,752	1,016	• Temporary Generation deployed that benefited 34 customers
					10/5/2019		1,020	
					10/9/2019		1,020	
					10/23/2019		1,029	
					10/26/2019		1,030	
					9/7/2020		1,347	
					9/27/2020		1,368	
					10/14/2020		1,396	

TABLE 9-2:
LIST OF FREQUENTLY DE-ENERGIZED CIRCUITS
(CONTINUED)

Entry Number	ID of Circuit	Circuit Name	Transmission (Tx)/ Distribution (Dx)	County	Dates of Outages	Number of Customers Served by Circuit (as of December 1, 2022)	Number of Customers Affected	Measures Taken, or Planned to Be Taken, to Reduce the Need for and Impact of Future PSPS of Circuit
					10/21/2020		1,410	
					10/25/2020		1,412	
					8/17/2021		881	
120	102831106	PARADISE 1106	Dx	BUTTE	9/25/2019	739	243	
					10/5/2019		289	
					10/9/2019		289	
					10/23/2019		290	
					10/26/2019		292	
					9/7/2020		402	
					9/27/2020		415	
					10/14/2020		423	
					10/21/2020		434	
					10/25/2020		435	
					8/17/2021		107	
121	152201101	PIKE CITY 1101	Dx	YUBA	10/9/2019	385	392	• 1 Sectionalizing device added or replaced
					10/23/2019		390	
					10/26/2019		391	
					9/7/2020		384	
					9/27/2020		384	
					10/25/2020		388	
122	152201102	PIKE CITY 1102	Dx	SIERRA	10/9/2019	24	24	

TABLE 9-2:
LIST OF FREQUENTLY DE-ENERGIZED CIRCUITS
(CONTINUED)

Entry Number	ID of Circuit	Circuit Name	Transmission (Tx)/ Distribution (Dx)	County	Dates of Outages	Number of Customers Served by Circuit (as of December 1, 2022)	Number of Customers Affected	Measures Taken, or Planned to Be Taken, to Reduce the Need for and Impact of Future PSPS of Circuit
					10/23/2019		24	
					10/26/2019		24	
					9/7/2020		24	
					9/27/2020		24	
					10/25/2020		24	
123	163751101	PINE GROVE 1101	Dx	AMADOR	10/14/2018	1,338	1,335	• Mitigated by PSPS protocols
					10/9/2019		1,336	
					10/23/2019		1,335	
					10/26/2019		1,334	
					10/25/2020		1,345	
124	163751102	PINE GROVE 1102	Dx	AMADOR	10/14/2018	4,243	2,967	• 1 Sectionalizing device added or replaced • 11.3 miles of overhead hardening completed • Mitigated by PSPS protocols • Temporary Generation deployed that benefited 1 customer
					10/9/2019		4,239	
					10/23/2019		4,237	
					10/26/2019		4,238	
					9/7/2020		3,458	
					9/27/2020		3,626	
					10/25/2020		4,229	

TABLE 9-2:
LIST OF FREQUENTLY DE-ENERGIZED CIRCUITS
(CONTINUED)

Entry Number	ID of Circuit	Circuit Name	Transmission (Tx)/ Distribution (Dx)	County	Dates of Outages	Number of Customers Served by Circuit (as of December 1, 2022)	Number of Customers Affected	Measures Taken, or Planned to Be Taken, to Reduce the Need for and Impact of Future PSPS of Circuit
125	103732101	PIT NO 3 2101	Dx	SHASTA	9/7/2020	145	150	
					10/21/2020		25	
					10/25/2020		126	
126	103501101	PIT NO 7 1101	Dx	SHASTA	10/9/2019	2	2	
					10/26/2019		2	
					9/7/2020		2	
					10/14/2020		2	
					10/21/2020		2	
					10/25/2020		2	
					8/17/2021		2	
127	153081109	PLACERVILLE 1109	Dx	EL DORADO	10/14/2018	570	505	• 1 MSO device replaced Mitigated by PSPS protocols • Temporary Generation deployed that benefited 563 customers
					10/9/2019		572	
					10/23/2019		570	
					10/26/2019		571	
					9/7/2020		502	
					9/27/2020		506	
					10/25/2020		571	
128	153081110	PLACERVILLE 1110	Dx	EL DORADO	10/14/2018	1,544	1,575	
					10/9/2019		1,574	
					10/23/2019		1,574	
					10/26/2019		1,573	

TABLE 9-2:
LIST OF FREQUENTLY DE-ENERGIZED CIRCUITS
(CONTINUED)

Entry Number	ID of Circuit	Circuit Name	Transmission (Tx)/ Distribution (Dx)	County	Dates of Outages	Number of Customers Served by Circuit (as of December 1, 2022)	Number of Customers Affected	Measures Taken, or Planned to Be Taken, to Reduce the Need for and Impact of Future PSPS of Circuit
					9/27/2020 10/25/2020		1,197 1,542	• 2 Sectionalizing devices added or replaced • Mitigated by PSPS protocols • Temporary Generation deployed that benefited 563 customers
129	153081111	PLACERVILLE 1111	Dx	EL DORADO	10/9/2019 10/23/2019 10/26/2019 9/7/2020 9/27/2020 10/25/2020	869	1,061 1,063 1,064 1,087 1,021 1,091	• 8 Sectionalizing devices added or replaced • Mitigated by PSPS protocols • Temporary Generation deployed that benefited 563 customers
130	153081112	PLACERVILLE 1112	Dx	EL DORADO	10/9/2019 10/23/2019 10/26/2019 9/7/2020 9/27/2020	2,079	2,049 2,053 2,055 2,052 2,059	

TABLE 9-2:
LIST OF FREQUENTLY DE-ENERGIZED CIRCUITS
(CONTINUED)

Entry Number	ID of Circuit	Circuit Name	Transmission (Tx)/ Distribution (Dx)	County	Dates of Outages	Number of Customers Served by Circuit (as of December 1, 2022)	Number of Customers Affected	Measures Taken, or Planned to Be Taken, to Reduce the Need for and Impact of Future PSPS of Circuit
					10/25/2020		2,065	• 7 Sectionalizing devices added or replaced • 0.1 line miles undergrounded • Mitigated by PSPS protocols • Temporary Generation deployed that benefited 563 customers
131	153082106	PLACERVILLE 2106	Dx	EL DORADO	10/14/2018	5,169	5,094	• 0.2 line miles undergrounded • Temporary Generation deployed that benefited 563 customers
					10/9/2019		5,142	
					10/23/2019		4,903	
					10/26/2019		5,109	
					9/7/2020		5,139	
					9/27/2020		5,155	
					10/25/2020		5,165	
132	42281105	POTTER VALLEY P H 1105	Dx	MENDOCINO	10/9/2019	786	778	
					10/23/2019		71	
					10/26/2019		780	

TABLE 9-2:
LIST OF FREQUENTLY DE-ENERGIZED CIRCUITS
(CONTINUED)

Entry Number	ID of Circuit	Circuit Name	Transmission (Tx)/ Distribution (Dx)	County	Dates of Outages	Number of Customers Served by Circuit (as of December 1, 2022)	Number of Customers Affected	Measures Taken, or Planned to Be Taken, to Reduce the Need for and Impact of Future PSPS of Circuit
					10/25/2020		120	• 1 Sectionalizing device added or replaced • 1.6 miles of overhead hardening completed • 0.1 line miles undergrounded • Mitigated by PSPS protocols
133	43291104	PUEBLO 1104	Dx	NAPA	10/9/2019	2,005	1,926	• 3 Sectionalizing devices added or replaced • 1 MSO device replaced
					10/26/2019		604	
					11/20/2019		611	
					10/14/2020		265	
					10/25/2020		265	
					8/17/2021		257	
					10/11/2021		37	
134	43291105	PUEBLO 1105	Dx	NAPA	10/9/2019	2,095	2,034	• 3 Sectionalizing devices added or replaced • 2 MSO device replaced
					10/26/2019		478	
					11/20/2019		449	
					10/14/2020		434	
					10/25/2020		477	

TABLE 9-2:
LIST OF FREQUENTLY DE-ENERGIZED CIRCUITS
(CONTINUED)

Entry Number	ID of Circuit	Circuit Name	Transmission (Tx)/ Distribution (Dx)	County	Dates of Outages	Number of Customers Served by Circuit (as of December 1, 2022)	Number of Customers Affected	Measures Taken, or Planned to Be Taken, to Reduce the Need for and Impact of Future PSPS of Circuit
					8/17/2021		117	
					10/11/2021		117	
135	43292102	PUEBLO 2102	Dx	NAPA	10/9/2019	2,212	382	• 9 Sectionalizing devices added or replaced • 2 miles of overhead hardening completed
					10/23/2019		81	
					10/26/2019		359	
					11/20/2019		220	
					9/7/2020		42	
					10/14/2020		72	
					10/25/2020		379	
					8/17/2021		66	
136	43292103	PUEBLO 2103	Dx	NAPA	10/9/2019	4,674	4,605	• 7 Sectionalizing devices added or replaced
					10/23/2019		158	
					10/26/2019		651	
					11/20/2019		181	
					9/7/2020		11	
					10/14/2020		35	
					10/25/2020		559	
					8/17/2021		216	
137	63681102	PUTAH CREEK 1102	Dx	YOLO	6/8/2019	863	276	
					10/9/2019		909	
					10/26/2019		911	

TABLE 9-2:
LIST OF FREQUENTLY DE-ENERGIZED CIRCUITS
(CONTINUED)

Entry Number	ID of Circuit	Circuit Name	Transmission (Tx)/ Distribution (Dx)	County	Dates of Outages	Number of Customers Served by Circuit (as of December 1, 2022)	Number of Customers Affected	Measures Taken, or Planned to Be Taken, to Reduce the Need for and Impact of Future PSPS of Circuit
					11/20/2019		9	• 26.6 miles of overhead hardening completed • 0.4 line miles undergrounded • Mitigated by PSPS protocols
					10/25/2020		185	
					8/17/2021		159	
					10/11/2021		272	
138	63681105	PUTAH CREEK 1105	Dx	YOLO	10/9/2019	1,065	869	• 4 Sectionalizing devices added or replaced
					10/26/2019		876	
					8/17/2021		9	
					9/20/2021		9	
					10/11/2021		36	
139	103541101	RED BLUFF 1101	Dx	TEHAMA	10/9/2019	1,574	1,560	• 2 Sectionalizing devices added or replaced • 1 MSO device replaced • Mitigated by PSPS protocols
					10/26/2019		746	
					11/20/2019		745	
					10/25/2020		173	
					8/17/2021		685	
					10/11/2021		1,014	
140	103541103	RED BLUFF 1103	Dx	TEHAMA	10/9/2019	2,646	2,641	• Mitigated by PSPS protocols
					10/26/2019		212	
					11/20/2019		212	
					8/17/2021		214	

TABLE 9-2:
LIST OF FREQUENTLY DE-ENERGIZED CIRCUITS
(CONTINUED)

Entry Number	ID of Circuit	Circuit Name	Transmission (Tx)/ Distribution (Dx)	County	Dates of Outages	Number of Customers Served by Circuit (as of December 1, 2022)	Number of Customers Affected	Measures Taken, or Planned to Be Taken, to Reduce the Need for and Impact of Future PSPS of Circuit
					10/11/2021		214	
141	103541104	RED BLUFF 1104	Dx	TEHAMA	10/9/2019	1,494	1,492	• 2 Sectionalizing devices added or replaced
					10/26/2019		911	
					11/20/2019		852	
					8/17/2021		865	
					10/11/2021		865	
142	103541105	RED BLUFF 1105	Dx	TEHAMA	10/9/2019	1,911	1,847	• 7 Sectionalizing devices added or replaced • Mitigated by PSPS protocols
					10/26/2019		934	
					11/20/2019		936	
					8/17/2021		981	
143	43191101	REDBUD 1101	Dx	LAKE	10/14/2018	1,957	660	• 2 Sectionalizing devices added or replaced
					10/9/2019		1,957	
					10/26/2019		1,956	
					11/20/2019		9	
					10/25/2020		1,282	
					8/17/2021		560	
					10/11/2021		124	
144	43321101	RINCON 1101	Dx	SONOMA	10/9/2019	3,598	3,665	
					10/23/2019		3,666	
					10/26/2019		3,666	
					11/20/2019		3,471	

TABLE 9-2:
LIST OF FREQUENTLY DE-ENERGIZED CIRCUITS
(CONTINUED)

Entry Number	ID of Circuit	Circuit Name	Transmission (Tx)/ Distribution (Dx)	County	Dates of Outages	Number of Customers Served by Circuit (as of December 1, 2022)	Number of Customers Affected	Measures Taken, or Planned to Be Taken, to Reduce the Need for and Impact of Future PSPS of Circuit
					9/7/2020 10/25/2020 8/17/2021		3,649 1,571 21	• 5 Sectionalizing devices added or replaced • Temporary Generation deployed
145	43321102	RINCON 1102	Dx	SONOMA	10/9/2019 10/23/2019 10/26/2019 9/7/2020	4,793	4,574 4,576 4,577 4,558	• 3 Sectionalizing devices added or replaced • Mitigated by PSPS protocols
146	43321103	RINCON 1103	Dx	SONOMA	9/25/2019 10/9/2019 10/23/2019 10/26/2019 11/20/2019 9/7/2020 10/14/2020 10/25/2020 8/17/2021	1,906	147 2,014 2,016 2,017 2,013 2,020 20 166 281	• 1 Sectionalizing device added or replaced • 0.3 miles of overhead hardening completed • 1.5 line miles undergrounded
147	43321104	RINCON 1104	Dx	SONOMA	10/9/2019 10/23/2019 10/26/2019	3,987	4,016 4,016 4,014	

TABLE 9-2:
LIST OF FREQUENTLY DE-ENERGIZED CIRCUITS
(CONTINUED)

Entry Number	ID of Circuit	Circuit Name	Transmission (Tx)/ Distribution (Dx)	County	Dates of Outages	Number of Customers Served by Circuit (as of December 1, 2022)	Number of Customers Affected	Measures Taken, or Planned to Be Taken, to Reduce the Need for and Impact of Future PSPS of Circuit
					9/7/2020		3,951	• 1 Sectionalizing device added or replaced • 0.1 miles of overhead hardening completed • 1.3 line miles undergrounded • Mitigated by PSPS protocols
148	163692101	SALT SPRINGS 2101	Dx	CALAVERAS	10/9/2019	392	387	
					10/23/2019		387	
					10/26/2019		387	
					9/7/2020		384	
					9/27/2020		384	
					10/25/2020		386	
149	163692102	SALT SPRINGS 2102	Dx	CALAVERAS	10/9/2019	1,991	1,990	
					10/23/2019		1,989	
					10/26/2019		1,989	
					9/7/2020		1,973	
					9/27/2020		1,976	

TABLE 9-2:
LIST OF FREQUENTLY DE-ENERGIZED CIRCUITS
(CONTINUED)

Entry Number	ID of Circuit	Circuit Name	Transmission (Tx)/ Distribution (Dx)	County	Dates of Outages	Number of Customers Served by Circuit (as of December 1, 2022)	Number of Customers Affected	Measures Taken, or Planned to Be Taken, to Reduce the Need for and Impact of Future PSPS of Circuit
					10/25/2020		1,978	• 1 MSO device installations or replacement planned • 1.2 miles of overhead hardening completed • Mitigated by PSPS protocols
150	42151104	SANTA ROSA A 1104	Dx	SONOMA	10/9/2019	3,394	3,288	• 3 Sectionalizing devices added or replaced • 2 MSO device replaced • 1 MSO device installations or replacement planned • Mitigated by PSPS protocols
					10/23/2019		2,309	
					10/26/2019		2,310	
					11/20/2019		428	
					9/7/2020		456	
					10/25/2020		458	
151	258131101	SCE TEHACHAPI 1101	Dx	KERN	12/3/2020	2	3	
					1/18/2021		3	
					9/20/2021		3	
					10/14/2021		3	
152	152431101	SHADY GLEN 1101	Dx	PLACER	10/9/2019	1,699	1,833	

TABLE 9-2:
LIST OF FREQUENTLY DE-ENERGIZED CIRCUITS
(CONTINUED)

Entry Number	ID of Circuit	Circuit Name	Transmission (Tx)/ Distribution (Dx)	County	Dates of Outages	Number of Customers Served by Circuit (as of December 1, 2022)	Number of Customers Affected	Measures Taken, or Planned to Be Taken, to Reduce the Need for and Impact of Future PSPS of Circuit
					10/23/2019		1,834	• 8 Sectionalizing devices added or replaced • 1.4 miles of overhead hardening completed • 3.3 line miles undergrounded • Temporary Generation deployed
					10/26/2019		1,834	
					9/7/2020		22	
					10/25/2020		1,852	
153	152431102	SHADY GLEN 1102	Dx	PLACER	10/9/2019	889	736	
					10/23/2019		736	
					10/26/2019		736	
					9/7/2020		667	
					9/27/2020		463	
					10/25/2020		736	
154	153652109	SHINGLE SPRINGS 2109	Dx	EL DORADO	10/14/2018	3,558	326	
					10/9/2019		3,500	
					10/23/2019		579	
					10/26/2019		3,498	

TABLE 9-2:
LIST OF FREQUENTLY DE-ENERGIZED CIRCUITS
(CONTINUED)

Entry Number	ID of Circuit	Circuit Name	Transmission (Tx)/ Distribution (Dx)	County	Dates of Outages	Number of Customers Served by Circuit (as of December 1, 2022)	Number of Customers Affected	Measures Taken, or Planned to Be Taken, to Reduce the Need for and Impact of Future PSPS of Circuit
					10/25/2020		1,695	• 19.2 miles of overhead hardening completed • 5.6 line miles undergrounded • Mitigated by PSPS protocols
155	43432102	SILVERADO 2102	Dx	NAPA	10/14/2018	1,299	200	• 7 Sectionalizing devices added or replaced • 2 MSO device replaced • 2 MSO device installations or replacement planned • 3.6 miles of overhead hardening completed
					10/9/2019		1,278	
					10/23/2019		759	
					10/26/2019		885	
					11/20/2019		986	
					9/7/2020		344	
					10/14/2020		690	
					10/25/2020		543	
					8/17/2021		182	
					10/11/2021		335	
156	43432103	SILVERADO 2103	Dx	NAPA	10/9/2019	939	935	• 3 Sectionalizing devices added or replaced
					10/23/2019		14	
					10/26/2019		388	
					11/20/2019		362	
					9/7/2020		3	

TABLE 9-2:
LIST OF FREQUENTLY DE-ENERGIZED CIRCUITS
(CONTINUED)

Entry Number	ID of Circuit	Circuit Name	Transmission (Tx)/ Distribution (Dx)	County	Dates of Outages	Number of Customers Served by Circuit (as of December 1, 2022)	Number of Customers Affected	Measures Taken, or Planned to Be Taken, to Reduce the Need for and Impact of Future PSPS of Circuit
					10/25/2020		278	
					8/17/2021		3	
157	43432104	SILVERADO 2104	Dx	NAPA	10/14/2018	3,613	2,222	• 17 Sectionalizing devices added or replaced • 7 miles of overhead hardening completed • 5.3 line miles undergrounded • Temporary Generation deployed that benefited 731 customers
					10/9/2019		3,772	
					10/23/2019		2,224	
					10/26/2019		2,369	
					11/20/2019		2,372	
					9/7/2020		2,350	
					10/14/2020		1,010	
					10/25/2020		2,080	
					8/17/2021		1,815	
					10/11/2021		774	
158	43432105	SILVERADO 2105	Dx	NAPA	10/9/2019	2,186	2,272	
					10/23/2019		342	
					10/26/2019		1,041	
					11/20/2019		921	
					9/7/2020		159	
					10/14/2020		179	

TABLE 9-2:
LIST OF FREQUENTLY DE-ENERGIZED CIRCUITS
(CONTINUED)

Entry Number	ID of Circuit	Circuit Name	Transmission (Tx)/ Distribution (Dx)	County	Dates of Outages	Number of Customers Served by Circuit (as of December 1, 2022)	Number of Customers Affected	Measures Taken, or Planned to Be Taken, to Reduce the Need for and Impact of Future PSPS of Circuit
					10/25/2020		433	• 10 Sectionalizing devices added or replaced • 2 MSO device replaced • 1.8 miles of overhead hardening completed • Mitigated by PSPS protocols • Temporary Generation deployed
159	153791101	SMARTVILLE 1101	Dx	YUBA	9/23/2019	264	255	• Mitigated by PSPS protocols
					9/25/2019		255	
					10/9/2019		255	
					10/23/2019		255	
					10/26/2019		255	
160	42721102	SONOMA 1102	Dx	SONOMA	10/9/2019	3,396	3,372	• 2 Sectionalizing devices added or replaced
					10/23/2019		270	
					10/26/2019		270	
					10/14/2020		153	
					10/25/2020		153	

TABLE 9-2:
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(CONTINUED)

Entry Number	ID of Circuit	Circuit Name	Transmission (Tx)/ Distribution (Dx)	County	Dates of Outages	Number of Customers Served by Circuit (as of December 1, 2022)	Number of Customers Affected	Measures Taken, or Planned to Be Taken, to Reduce the Need for and Impact of Future PSPS of Circuit
161	42721103	SONOMA 1103	Dx	SONOMA	10/9/2019	2,145	2,101	• 3 Sectionalizing devices added or replaced
					10/23/2019		314	
					10/26/2019		314	
					10/14/2020		311	
					10/25/2020		287	
					8/17/2021		37	
162	42721106	SONOMA 1106	Dx	SONOMA	10/9/2019	3,133	3,103	• 3 Sectionalizing devices added or replaced
					10/23/2019		167	
					10/26/2019		167	
					10/14/2020		95	
					10/25/2020		79	
163	152251101	SPAULDING 1101	Dx	NEVADA	10/9/2019	163	161	
					10/26/2019		161	
					9/7/2020		160	
					9/27/2020		70	
					10/25/2020		163	
164	162821701	STANISLAUS 1701	Dx	CALAVERAS	10/9/2019	2,124	1,780	• Mitigated by PSPS protocols
					10/23/2019		1,778	
					10/26/2019		1,778	
					9/7/2020		1,785	
					10/25/2020		1,790	

TABLE 9-2:
LIST OF FREQUENTLY DE-ENERGIZED CIRCUITS
(CONTINUED)

Entry Number	ID of Circuit	Circuit Name	Transmission (Tx)/ Distribution (Dx)	County	Dates of Outages	Number of Customers Served by Circuit (as of December 1, 2022)	Number of Customers Affected	Measures Taken, or Planned to Be Taken, to Reduce the Need for and Impact of Future PSPS of Circuit
165	162821702	STANISLAUS 1702	Dx	CALAVERAS	10/9/2019	4,891	4,889	• 1 MSO device installations or replacement planned • 1.6 miles of overhead hardening completed • Mitigated by PSPS protocols
					10/23/2019		4,894	
					10/26/2019		4,894	
					9/7/2020		4,882	
					10/25/2020		4,891	
166	103561101	STILLWATER 1101	Dx	SHASTA	10/9/2019	680	695	• 1.8 miles of overhead hardening completed
					10/26/2019		695	
					10/14/2020		36	
					10/21/2020		700	
					10/25/2020		702	
					8/17/2021		706	
167	103561102	STILLWATER 1102	Dx	SHASTA	10/9/2019	1,363	1,371	• 2.8 miles of overhead hardening completed
					10/26/2019		1,374	
					10/14/2020		724	
					10/21/2020		1,367	
					10/25/2020		1,370	
					8/17/2021		1,384	
168	102971111		Dx	BUTTE	10/5/2019	2,118	578	

TABLE 9-2:
LIST OF FREQUENTLY DE-ENERGIZED CIRCUITS
(CONTINUED)

Entry Number	ID of Circuit	Circuit Name	Transmission (Tx)/ Distribution (Dx)	County	Dates of Outages	Number of Customers Served by Circuit (as of December 1, 2022)	Number of Customers Affected	Measures Taken, or Planned to Be Taken, to Reduce the Need for and Impact of Future PSPS of Circuit
		SYCAMORE CREEK 1111			10/9/2019		1,882	• 3 Sectionalizing devices added or replaced • Mitigated by PSPS protocols • Temporary Generation deployed
					10/23/2019		596	
					10/26/2019		595	
					9/27/2020		456	
					10/14/2020		508	
					10/25/2020		509	
					10/11/2021		580	
169	252931102	TEJON 1102	Dx	KERN	10/9/2019	686	596	• Temporary Generation deployed that benefited 2 customers
					10/26/2019		597	
					9/7/2020		592	
					12/3/2020		594	
					9/20/2021		598	
					10/11/2021		595	
					10/14/2021		595	
170	252931103	TEJON 1103	Dx	KERN	10/9/2019	110	83	• Mitigated by PSPS protocols
					10/23/2019		15	
					10/26/2019		15	
					9/7/2020		15	
					12/3/2020		2	

TABLE 9-2:
LIST OF FREQUENTLY DE-ENERGIZED CIRCUITS
(CONTINUED)

Entry Number	ID of Circuit	Circuit Name	Transmission (Tx)/ Distribution (Dx)	County	Dates of Outages	Number of Customers Served by Circuit (as of December 1, 2022)	Number of Customers Affected	Measures Taken, or Planned to Be Taken, to Reduce the Need for and Impact of Future PSPS of Circuit
					1/18/2021		2	
					10/11/2021		15	
					10/14/2021		15	
171	161380201	TIGER CREEK 0201	Dx	AMADOR	10/14/2018	14	12	• 1 Sectionalizing device added or replaced • Mitigated by PSPS protocols
					10/9/2019		13	
					10/23/2019		13	
					10/26/2019		13	
					9/7/2020		14	
					9/27/2020		14	
					10/25/2020		14	
172	103571105	TYLER 1105	Dx	TEHAMA	10/9/2019	1,914	1,654	• 1 Sectionalizing device added or replaced • Temporary Generation deployed
					10/26/2019		1,657	
					11/20/2019		763	
					10/25/2020		227	
					8/17/2021		765	
					9/20/2021		237	
					10/11/2021		766	
173	42871101	UPPER LAKE 1101	Dx	LAKE	10/9/2019	1,160	1,131	
					10/23/2019		10	
					10/26/2019		1,231	

TABLE 9-2:
LIST OF FREQUENTLY DE-ENERGIZED CIRCUITS
(CONTINUED)

Entry Number	ID of Circuit	Circuit Name	Transmission (Tx)/ Distribution (Dx)	County	Dates of Outages	Number of Customers Served by Circuit (as of December 1, 2022)	Number of Customers Affected	Measures Taken, or Planned to Be Taken, to Reduce the Need for and Impact of Future PSPS of Circuit
					10/25/2020		538	• 1 MSO device replaced • 1.1 miles of overhead hardening completed • Mitigated by PSPS protocols
174	63601104	VACAVILLE 1104	Dx	SOLANO	10/9/2019	2,044	2,738	• 2 Sectionalizing devices added or replaced • 1 MSO device replaced • 9.9 miles of overhead hardening completed • 2.7 line miles undergrounded
					10/26/2019		1,537	
					10/25/2020		52	
					8/17/2021		25	
					9/20/2021		802	
					10/11/2021		302	
175	63601108	VACAVILLE 1108	Dx	SOLANO	10/9/2019	2,324	2,314	• 1 Sectionalizing device added or replaced • 1 MSO device installations or replacement planned
					10/26/2019		367	
					11/20/2019		78	
					10/25/2020		230	
					8/17/2021		295	
					9/20/2021		45	

TABLE 9-2:
LIST OF FREQUENTLY DE-ENERGIZED CIRCUITS
(CONTINUED)

Entry Number	ID of Circuit	Circuit Name	Transmission (Tx)/ Distribution (Dx)	County	Dates of Outages	Number of Customers Served by Circuit (as of December 1, 2022)	Number of Customers Affected	Measures Taken, or Planned to Be Taken, to Reduce the Need for and Impact of Future PSPS of Circuit
					10/11/2021		374	
176	102541101	VOLTA 1101	Dx	TEHAMA	10/9/2019	1,267	1,285	• 36.8 miles of overhead hardening completed • 3.7 line miles undergrounded • Temporary Generation deployed that benefited 87 customers
					10/23/2019		748	
					10/26/2019		1,285	
					11/20/2019		1,277	
					9/7/2020		1,289	
					9/27/2020		1,291	
					10/14/2020		1,287	
					10/25/2020		1,290	
					8/17/2021		1,126	
					10/11/2021		604	
177	102541102	VOLTA 1102	Dx	SHASTA	10/9/2019	2,582	2,563	• 26.3 miles of overhead hardening completed • Temporary Generation deployed that benefited 90 customers
					10/26/2019		2,562	
					11/20/2019		2,513	
					9/7/2020		2,558	
					9/27/2020		2,573	
					10/14/2020		2,572	
					10/25/2020		2,574	
					8/17/2021		2,584	
178	152491101	WEIMAR 1101	Dx	PLACER	10/9/2019	1,764	1,616	
					10/23/2019		1,617	

TABLE 9-2:
LIST OF FREQUENTLY DE-ENERGIZED CIRCUITS
(CONTINUED)

Entry Number	ID of Circuit	Circuit Name	Transmission (Tx)/ Distribution (Dx)	County	Dates of Outages	Number of Customers Served by Circuit (as of December 1, 2022)	Number of Customers Affected	Measures Taken, or Planned to Be Taken, to Reduce the Need for and Impact of Future PSPS of Circuit
					10/26/2019		1,617	
					9/7/2020		27	
					10/25/2020		1,625	
179	152491102	WEIMAR 1102	Dx	PLACER	10/9/2019	825	631	
					10/23/2019		632	
					10/26/2019		632	
					10/25/2020		635	
180	163201101	WEST POINT 1101	Dx	AMADOR	10/14/2018	1,755	1,755	• 4.3 miles of overhead hardening completed • Mitigated by PSPS protocols
					10/9/2019		1,757	
					10/23/2019		1,754	
					10/26/2019		1,755	
					9/7/2020		1,750	
					9/27/2020		1,755	
					10/25/2020		1,758	
181	163201102	WEST POINT 1102	Dx	CALAVERAS	10/14/2018	2,848	2,176	• 1 Sectionalizing device added or replaced • Mitigated by PSPS protocols • Temporary Generation deployed
					10/9/2019		2,815	
					10/23/2019		2,815	
					10/26/2019		2,812	
					9/7/2020		2,808	
					9/27/2020		2,815	
					10/25/2020		2,826	

TABLE 9-2:
LIST OF FREQUENTLY DE-ENERGIZED CIRCUITS
(CONTINUED)

Entry Number	ID of Circuit	Circuit Name	Transmission (Tx)/ Distribution (Dx)	County	Dates of Outages	Number of Customers Served by Circuit (as of December 1, 2022)	Number of Customers Affected	Measures Taken, or Planned to Be Taken, to Reduce the Need for and Impact of Future PSPS of Circuit
182	152811105	WHEATLAND 1105	Dx	YUBA	10/9/2019	637	627	• Mitigated by PSPS protocols
					10/23/2019		197	
					10/26/2019		197	
183	103601101	WHITMORE 1101	Dx	SHASTA	10/9/2019	507	514	
					10/26/2019		513	
					11/20/2019		190	
					9/7/2020		311	
					10/25/2020		517	
					8/17/2021		271	
184	152271102	WISE 1102	Dx	PLACER	10/9/2019	1,740	1,700	• Mitigated by PSPS protocols • Temporary Generation deployed
					10/23/2019		648	
					10/26/2019		1,702	
185	24251101	WOODSIDE 1101	Dx	SAN MATEO	10/9/2019	1,762	1,742	• 2 Sectionalizing devices added or replaced
					10/23/2019		360	
					10/26/2019		1,601	
					10/14/2020		74	
					10/25/2020		699	
186	102911102	WYANDOTTE 1102	Dx	BUTTE	6/8/2019	2,562	146	• Mitigated by PSPS protocols
					9/23/2019		33	

TABLE 9-2:
LIST OF FREQUENTLY DE-ENERGIZED CIRCUITS
(CONTINUED)

Entry Number	ID of Circuit	Circuit Name	Transmission (Tx)/ Distribution (Dx)	County	Dates of Outages	Number of Customers Served by Circuit (as of December 1, 2022)	Number of Customers Affected	Measures Taken, or Planned to Be Taken, to Reduce the Need for and Impact of Future PSPS of Circuit
					9/25/2019		33	
					10/9/2019		2,850	
					10/23/2019		33	
					10/26/2019		33	
187	102911103	WYANDOTTE 1103	Dx	BUTTE	6/8/2019	1,715	1,602	• 1 Sectionalizing device added or replaced • 0.1 miles of overhead hardening completed • 50.4 line miles undergrounded
					9/23/2019		1,603	
					9/25/2019		1,600	
					10/5/2019		770	
					10/9/2019		2,160	
					10/23/2019		1,598	
					10/26/2019		1,598	
					11/20/2019		241	
					9/7/2020		1,350	
					9/27/2020		27	
					10/21/2020		23	
					10/25/2020		533	
188	102911105	WYANDOTTE 1105	Dx	BUTTE	9/23/2019	520	331	• 1 Sectionalizing device added or replaced • Mitigated by PSPS protocols
					9/25/2019		331	
					10/5/2019		330	
					10/9/2019		330	
					10/23/2019		329	

TABLE 9-2:
LIST OF FREQUENTLY DE-ENERGIZED CIRCUITS
(CONTINUED)

Entry Number	ID of Circuit	Circuit Name	Transmission (Tx)/ Distribution (Dx)	County	Dates of Outages	Number of Customers Served by Circuit (as of December 1, 2022)	Number of Customers Affected	Measures Taken, or Planned to Be Taken, to Reduce the Need for and Impact of Future PSPS of Circuit
					10/26/2019		330	
					9/7/2020		516	
					9/27/2020		1	
					10/14/2020		1	
					10/21/2020		1	
					10/25/2020		1	
189	102911106	WYANDOTTE 1106	Dx	BUTTE	6/8/2019	1,575	164	• Mitigated by PSPS protocols
					9/23/2019		166	
					9/25/2019		166	
					10/9/2019		1,552	
					10/23/2019		9	
					10/26/2019		167	
190	102911107	WYANDOTTE 1107	Dx	BUTTE	6/8/2019	2,880	1,912	• 3 Sectionalizing devices added or replaced
					9/23/2019		1,911	
					9/25/2019		1,911	
					10/9/2019		2,735	
					10/23/2019		1,913	
					10/26/2019		1,913	
					9/7/2020		945	
					9/27/2020		547	
					10/25/2020		757	

TABLE 9-2:
LIST OF FREQUENTLY DE-ENERGIZED CIRCUITS
(CONTINUED)

Entry Number	ID of Circuit	Circuit Name	Transmission (Tx)/ Distribution (Dx)	County	Dates of Outages	Number of Customers Served by Circuit (as of December 1, 2022)	Number of Customers Affected	Measures Taken, or Planned to Be Taken, to Reduce the Need for and Impact of Future PSPS of Circuit
191	102911109	WYANDOTTE 1109	Dx	BUTTE	6/8/2019	3,392	2,171	• 2 Sectionalizing devices added or replaced • 0.01 miles of overhead hardening completed • 0.4 line miles undergrounded • Mitigated by PSPS protocols
					9/23/2019		2,288	
					9/25/2019		2,287	
					10/9/2019		3,460	
					10/23/2019		2,287	
					10/26/2019		2,289	
192	102911110	WYANDOTTE 1110	Dx	BUTTE	9/23/2019	2,669	1,638	• 2 Sectionalizing devices added or replaced
					9/25/2019		1,638	
					10/9/2019		2,673	
					10/23/2019		1,637	
					10/26/2019		1,638	
193	ETL.6220	BRIDGEVILLE-GARBERVILLE 60 KV	Tx	HUMBOLDT	10/26/2019	0	0	• Mitigated by PSPS Protocols • Transmission Islanding • 1224 Transmission tags completed • 38.1 ROW Expansion miles completed
					9/7/2020		0	
					10/14/2020		0	
					10/25/2020		0	

**TABLE 9-2:
LIST OF FREQUENTLY DE-ENERGIZED CIRCUITS
(CONTINUED)**

Entry Number	ID of Circuit	Circuit Name	Transmission (Tx)/ Distribution (Dx)	County	Dates of Outages	Number of Customers Served by Circuit (as of December 1, 2022)	Number of Customers Affected	Measures Taken, or Planned to Be Taken, to Reduce the Need for and Impact of Future PSPS of Circuit
194	ETL.1180	BUTTE VALLEY-CARIBOU 115 KV	Tx	PLUMAS	9/7/2020	0	0	• 90 Transmission tags completed • 0.1 ROW Expansion miles completed
					9/27/2020		0	
					10/14/2020		0	
					10/21/2020		0	
					10/25/2020		0	
195	ETL.3190	CARIBOU-PALERMO 115 KV	Tx	BUTTE, PLUMAS	10/9/2019	0	0	• 23.5 miles replaced or eliminated • Mitigated by PSPS Protocols • 1215 Transmission tags completed
					10/23/2019		0	
					10/26/2019		0	
196	ETL.4440	CARIBOU-TABLE MOUNTAIN 230 KV	Tx	BUTTE, PLUMAS	9/7/2020	0	0	• Transmission Islanding • 1344 Transmission tags completed
					9/27/2020		0	
					10/14/2020		0	
					10/21/2020		0	
					10/25/2020		0	
197	ETL.6300	CARIBOU-WESTWOOD 60 KV	Tx	LASSEN, PLUMAS	9/7/2020	0	6	
					10/14/2020		1	
					10/21/2020		1	

TABLE 9-2:
LIST OF FREQUENTLY DE-ENERGIZED CIRCUITS
(CONTINUED)

Entry Number	ID of Circuit	Circuit Name	Transmission (Tx)/ Distribution (Dx)	County	Dates of Outages	Number of Customers Served by Circuit (as of December 1, 2022)	Number of Customers Affected	Measures Taken, or Planned to Be Taken, to Reduce the Need for and Impact of Future PSPS of Circuit
					10/25/2020		1	• Mitigated by PSPS Protocols • 674 Transmission tags completed • 18.7 ROW Expansion miles completed
198	ETL.6320	CENTERVILLE-TABLE MOUNTAIN 60 KV	Tx	BUTTE	6/8/2019 9/25/2019 10/5/2019 10/9/2019 10/23/2019 10/26/2019	1	1 0 0 1 1 1	• 3 segmentation devices installed • Mitigated by PSPS Protocols • 356 Transmission tags completed • 21.5 ROW Expansion miles completed
199	ETL.6330	CENTERVILLE-TABLE MOUNTAIN-OROVILLE 60 KV	Tx	BUTTE	6/8/2019 9/25/2019 10/5/2019 10/9/2019 10/23/2019 10/26/2019	0	0 0 0 0 0 0	• 3 segmentation devices installed • Mitigated by PSPS Protocols • 395 Transmission tags completed • 25.6 ROW Expansion miles completed
200	ETL.6470		Tx		10/9/2019	0	0	

TABLE 9-2:
LIST OF FREQUENTLY DE-ENERGIZED CIRCUITS
(CONTINUED)

Entry Number	ID of Circuit	Circuit Name	Transmission (Tx)/ Distribution (Dx)	County	Dates of Outages	Number of Customers Served by Circuit (as of December 1, 2022)	Number of Customers Affected	Measures Taken, or Planned to Be Taken, to Reduce the Need for and Impact of Future PSPS of Circuit
		COLGATE-ALLEGHANY 60 KV		NEVADA, SIERRA, YUBA	10/23/2019 10/26/2019 9/7/2020 10/25/2020		0 0 0 0	
201	ETL.6480	COLGATE-CHALLENGE 60 KV	Tx	YUBA	10/9/2019 10/23/2019 10/26/2019 9/7/2020 10/25/2020	0	0 0 0 0 0	• Mitigated by PSPS Protocols • 247 Transmission tags completed • 13.1 ROW Expansion miles completed
202	ETL.6490	COLGATE-GRASS VALLEY 60 KV	Tx	NEVADA, YUBA	10/9/2019 10/23/2019 10/26/2019	0	0 0 0	• Mitigated by PSPS Protocols • 396 Transmission tags completed • 13.2 ROW Expansion miles completed
203	ETL.6500	COLGATE-PALERMO 60 KV	Tx	BUTTE, NEVADA, YUBA	6/8/2019 9/23/2019 9/25/2019	0	0 0 0	

TABLE 9-2:
LIST OF FREQUENTLY DE-ENERGIZED CIRCUITS
(CONTINUED)

Entry Number	ID of Circuit	Circuit Name	Transmission (Tx)/ Distribution (Dx)	County	Dates of Outages	Number of Customers Served by Circuit (as of December 1, 2022)	Number of Customers Affected	Measures Taken, or Planned to Be Taken, to Reduce the Need for and Impact of Future PSPS of Circuit
					10/9/2019 10/26/2019		0 0	• 2 segmentation devices installed • Mitigated by PSPS Protocols • 587 Transmission tags completed
204	ETL.6520	COLGATE-SMARTVILLE #2 60 KV	Tx	NEVADA, YUBA	9/23/2019 9/25/2019 10/9/2019 10/26/2019	0	0 0 0 0	• Mitigated by PSPS Protocols • 313 Transmission tags completed
205	ETL.6650	COTTONWOOD-BENTON #2 60 KV	Tx	SHASTA	10/9/2019 10/26/2019 11/20/2019	0	0 0 0	• Mitigated by PSPS Protocols • 278 Transmission tags completed
206	ETL.6690	DEER CREEK-DRUM 60 KV	Tx	NEVADA, PLACER	10/9/2019 10/23/2019 10/26/2019 9/7/2020 10/25/2020	0	0 0 0 0 0	• ● Mitigated by PSPS Protocols • 316 Transmission tags completed • 6.2 ROW Expansion miles completed
207	ETL.6720	DESABLA-CENTERVILLE 60 KV	Tx	BUTTE	6/8/2019 9/25/2019	0	1 0	

TABLE 9-2:
LIST OF FREQUENTLY DE-ENERGIZED CIRCUITS
(CONTINUED)

Entry Number	ID of Circuit	Circuit Name	Transmission (Tx)/ Distribution (Dx)	County	Dates of Outages	Number of Customers Served by Circuit (as of December 1, 2022)	Number of Customers Affected	Measures Taken, or Planned to Be Taken, to Reduce the Need for and Impact of Future PSPS of Circuit
					10/5/2019		0	• 326 Transmission tags completed • 5.9 ROW Expansion miles completed
					10/9/2019		0	
					10/23/2019		0	
					10/26/2019		0	
208	ETL.6760	DRUM-GRASS VALLEY-WEIMAR 60 KV	Tx	NEVADA, PLACER	10/14/2018	0	0	• 2 segmentation devices installed • Mitigated by PSPS Protocols • 1648 Transmission tags completed
					10/9/2019		0	
					10/23/2019		1	
					10/26/2019		1	
					9/7/2020		0	
					10/25/2020		0	
209	ETL.4393	DRUM-HIGGINS 115 KV	Tx	NEVADA, PLACER	10/9/2019	0	0	• Mitigated by PSPS Protocols • 735 Transmission tags completed • 27.3 ROW Expansion miles completed
					10/23/2019		0	
					10/26/2019		0	
					9/7/2020		0	
					10/25/2020		0	
210	ETL.1420	DRUM-RIO OSO #1 115 KV	Tx	NEVADA, PLACER, SUTTER	10/9/2019	0	0	
					10/23/2019		0	
					10/26/2019		0	
					9/7/2020		0	

TABLE 9-2:
LIST OF FREQUENTLY DE-ENERGIZED CIRCUITS
(CONTINUED)

Entry Number	ID of Circuit	Circuit Name	Transmission (Tx)/ Distribution (Dx)	County	Dates of Outages	Number of Customers Served by Circuit (as of December 1, 2022)	Number of Customers Affected	Measures Taken, or Planned to Be Taken, to Reduce the Need for and Impact of Future PSPS of Circuit
					10/25/2020		0	• 7.7 miles replaced or eliminated • Mitigated by PSPS Protocols • 852 Transmission tags completed • 18.1 ROW Expansion miles completed
211	ETL.1430	DRUM-RIO OSO #2 115 KV	Tx	NEVADA, PLACER, SUTTER	10/9/2019	0	0	• Mitigated by PSPS Protocols • 495 Transmission tags completed • 18.1 ROW Expansion miles completed
					10/23/2019		0	
					10/26/2019		0	
					9/7/2020		0	
					10/25/2020		0	
212	ETL.1470	EAGLE ROCK-CORTINA 115 KV	Tx	COLUSA, LAKE, SONOMA	10/9/2019	0	0	• 3 segmentation devices installed • Mitigated by PSPS Protocols • 293 Transmission tags completed
					10/26/2019		0	
					11/20/2019		1	
213	ETL.1480		Tx	LAKE, SONOMA	10/9/2019	0	1	
					10/26/2019		0	

TABLE 9-2:
LIST OF FREQUENTLY DE-ENERGIZED CIRCUITS
(CONTINUED)

Entry Number	ID of Circuit	Circuit Name	Transmission (Tx)/ Distribution (Dx)	County	Dates of Outages	Number of Customers Served by Circuit (as of December 1, 2022)	Number of Customers Affected	Measures Taken, or Planned to Be Taken, to Reduce the Need for and Impact of Future PSPS of Circuit
		EAGLE ROCK-REDBUD 115 KV			11/20/2019		0	• Mitigated by PSPS Protocols • 284 Transmission tags completed
214	ETL.1530	EL DORADO-MISSOURI FLAT #1 115 KV	Tx	EL DORADO	10/9/2019 10/23/2019 10/26/2019 10/25/2020	0	1 0 0 0	• 289 Transmission tags completed
215	ETL.1540	EL DORADO-MISSOURI FLAT #2 115 KV	Tx	EL DORADO	10/9/2019 10/23/2019 10/26/2019 9/7/2020 10/25/2020	0	0 0 0 0 0	• Mitigated by PSPS Protocols • 66 Transmission tags completed
216	ETL.6722	FORKS OF THE BUTTE TAP 60 KV	Tx	BUTTE	6/8/2019 9/25/2019 10/5/2019	0	1 0 0	• 19 Transmission tags completed
217	ETL.6870	FRENCH MEADOWS-MIDDLE FORK 60 KV	Tx	PLACER	10/14/2018 10/9/2019 10/26/2019 9/7/2020 9/27/2020	4	3 0 0 0 0	

TABLE 9-2:
LIST OF FREQUENTLY DE-ENERGIZED CIRCUITS
(CONTINUED)

Entry Number	ID of Circuit	Circuit Name	Transmission (Tx)/ Distribution (Dx)	County	Dates of Outages	Number of Customers Served by Circuit (as of December 1, 2022)	Number of Customers Affected	Measures Taken, or Planned to Be Taken, to Reduce the Need for and Impact of Future PSPS of Circuit
					10/25/2020		0	• Mitigated by PSPS Protocols • 602 Transmission tags completed • 13.2 ROW Expansion miles completed
218	ETL.6880	FULTON-CALISTOGA 60 KV	Tx	LAKE, NAPA, SONOMA	10/14/2018 10/23/2019 10/26/2019 11/20/2019 10/25/2020 8/17/2021	0	0 0 0 0 0 0	• 3 segmentation devices installed • Mitigated by PSPS Protocols • 812 Transmission tags completed • 50.6 ROW Expansion miles completed
219	ETL.6890	FULTON-HOPLAND 60 KV	Tx	MENDOCINO, SONOMA	10/9/2019 10/23/2019 10/26/2019	0	0 0 0	• Mitigated by PSPS Protocols • 774 Transmission tags completed
220	ETL.2823	FULTON-LAKEVILLE-IGNACIO 230 KV	Tx	SONOMA	10/23/2019 10/26/2019 11/20/2019	0	0 0 0	• 7 Transmission tags completed
221	ETL.7290		Tx	SHASTA	10/9/2019	0	0	

TABLE 9-2:
LIST OF FREQUENTLY DE-ENERGIZED CIRCUITS
(CONTINUED)

Entry Number	ID of Circuit	Circuit Name	Transmission (Tx)/ Distribution (Dx)	County	Dates of Outages	Number of Customers Served by Circuit (as of December 1, 2022)	Number of Customers Affected	Measures Taken, or Planned to Be Taken, to Reduce the Need for and Impact of Future PSPS of Circuit
		KILARC-CEDAR CREEK 60 KV			10/26/2019		0	• 2 segmentation devices installed • Mitigated by PSPS Protocols • 646 Transmission tags completed • 12.2 ROW Expansion miles completed
					11/20/2019		0	
					9/7/2020		0	
					10/14/2020		0	
					10/21/2020		0	
					10/25/2020		0	
222	ETL.3505	KM GREEN 115 KV TAP	Tx	AMADOR	9/7/2020	1	1	• Mitigated by PSPS Protocols • 64 Transmission tags completed
					9/27/2020		1	
					10/25/2020		0	
223	ETL.8405	MIDDLE FORK #1 60 KV	Tx	PLACER	10/14/2018	3	0	• Mitigated by PSPS Protocols • 566 Transmission tags completed • 9.4 ROW Expansion miles completed
					9/25/2019		0	
					10/9/2019		0	
					10/23/2019		0	
					10/26/2019		0	
					9/7/2020		0	
					9/27/2020		0	
					10/25/2020		0	
224	ETL.5140		Tx		10/9/2019	0	0	

TABLE 9-2:
LIST OF FREQUENTLY DE-ENERGIZED CIRCUITS
(CONTINUED)

Entry Number	ID of Circuit	Circuit Name	Transmission (Tx)/ Distribution (Dx)	County	Dates of Outages	Number of Customers Served by Circuit (as of December 1, 2022)	Number of Customers Affected	Measures Taken, or Planned to Be Taken, to Reduce the Need for and Impact of Future PSPS of Circuit
		MIDDLE FORK-GOLD HILL 230 KV		EL DORADO, PLACER, SACRAMENTO	10/26/2019 9/7/2020 9/27/2020 10/25/2020		0 0 0 0	• Mitigated by PSPS Protocols • 1100 Transmission tags completed
225	ETL.6721	ORO FINO TAP 60 KV	Tx	BUTTE	6/8/2019 9/25/2019 10/5/2019	0	0 0 0	• 60 Transmission tags completed
226	ETL.7730	PALERMO-OROVILLE #1 60 KV	Tx	BUTTE	6/8/2019 9/23/2019 9/25/2019 10/9/2019 10/23/2019 10/26/2019	0	2 1 1 1 1 1	• Mitigated by PSPS Protocols • 88 Transmission tags completed
227	ETL.7740	PALERMO-OROVILLE #2 60 KV	Tx	BUTTE	6/8/2019 9/23/2019 9/25/2019	0	2 1 1	
228	ETL.3500		Tx	AMADOR, CALAVERAS	10/26/2019 9/7/2020	0	1 0	

TABLE 9-2:
LIST OF FREQUENTLY DE-ENERGIZED CIRCUITS
(CONTINUED)

Entry Number	ID of Circuit	Circuit Name	Transmission (Tx)/ Distribution (Dx)	County	Dates of Outages	Number of Customers Served by Circuit (as of December 1, 2022)	Number of Customers Affected	Measures Taken, or Planned to Be Taken, to Reduce the Need for and Impact of Future PSPS of Circuit
		SALT SPRINGS-TIGER CREEK 115 KV			9/27/2020 10/25/2020		0 1	• Mitigated by PSPS Protocols • 512 Transmission tags completed • 9.6 ROW Expansion miles completed
229	ETL.7980	SMARTVILLE-MARY SVILLE 60 K	Tx	YUBA	9/23/2019 10/9/2019 10/26/2019	1	1 1 1	• 2 segmentation devices installed • 177 Transmission tags completed
230	ETL.8000	SMARTVILLE-NICOL AUS #2 60 KV	Tx	PLACER, SUTTER, YUBA	9/23/2019 10/9/2019 10/26/2019	0	0 1 0	• 68 Transmission tags completed
231	ETL.5780	TIGER CREEK-ELECTRA 230KV	Tx	AMADOR	10/9/2019 10/23/2019 10/26/2019	0	1 1 0	• Mitigated by PSPS Protocols • 206 Transmission tags completed
232	ETL.5790	TIGER CREEK-VALLEY SPRINGS 230 KV	Tx	AMADOR, CALAVERAS	10/9/2019 10/23/2019 10/26/2019	0	0 0 0	• Mitigated by PSPS Protocols • 245 Transmission tags completed
233	ETL.7560	WEIMAR #1 60 KV	Tx	PLACER	10/14/2018	0	1	

TABLE 9-2:
LIST OF FREQUENTLY DE-ENERGIZED CIRCUITS
(CONTINUED)

Entry Number	ID of Circuit	Circuit Name	Transmission (Tx)/ Distribution (Dx)	County	Dates of Outages	Number of Customers Served by Circuit (as of December 1, 2022)	Number of Customers Affected	Measures Taken, or Planned to Be Taken, to Reduce the Need for and Impact of Future PSPS of Circuit
					9/25/2019 10/9/2019 10/23/2019 10/26/2019 9/7/2020		0 0 0 0 0	• Mitigated by PSPS Protocols • 547 Transmission tags completed • 14 ROW Expansion miles completed
234	ETL.8340	WEIMAR-HALSEY 60 KV	Tx	PLACER	10/9/2019 10/23/2019 10/26/2019	0	0 0 0	• Mitigated by PSPS Protocols • 178 Transmission tags completed
235	ETL.8350	WEST POINT-VALLEY SPRINGS 60 KV	Tx	AMADOR, CALAVERAS	10/14/2018 10/9/2019 10/23/2019 10/26/2019 9/7/2020 10/25/2020	0	1 0 0 0 0 0	• Mitigated by PSPS Protocols • Transmission Islanding • 468 Transmission tags completed • 21.6 ROW Expansion miles completed
236	ETL.4220	WOODLEAF-PALERMO 115 KV	Tx	BUTTE	9/25/2019 10/5/2019 10/9/2019 10/23/2019	0	0 0 0 0	

TABLE 9-2:
LIST OF FREQUENTLY DE-ENERGIZED CIRCUITS
(CONTINUED)

Entry Number	ID of Circuit	Circuit Name	Transmission (Tx)/ Distribution (Dx)	County	Dates of Outages	Number of Customers Served by Circuit (as of December 1, 2022)	Number of Customers Affected	Measures Taken, or Planned to Be Taken, to Reduce the Need for and Impact of Future PSPS of Circuit
					10/26/2019		0	• 2 segmentation devices installed • Mitigated by PSPS Protocols • 505 Transmission tags completed • 19.6 ROW Expansion miles completed
					9/7/2020		0	
					10/25/2020		0	

Appendix F.5 – Appendix D Areas of Continued Improvement

Appendix F.5.1 – PG&E-22-33 Progress on Filling Asset Inventory Data Gaps

Table PG&E-22-33-1 below lists current fill rates for a subset of the data elements. The table reflects progress in filling data gaps through 2022 and provides a baseline against which PG&E we can measure progress going forward.

TABLE PG&E-22-33-1:
CURRENT FILL RATES

ID	Asset Family	Asset Type	Asset Component	Asset Count - All	Install Date Fill Rate	Material Type Fill Rate	Manufacturer Fill Rate	Manufacture Date Fill Rate	Nominal Voltage Fill Rate
1	Transmission Overhead	Support Structure	Steel	24,519	80.6%	N/A	33.0%	20.1%	N/A
2	Transmission Overhead	Support Structure	Non-Steel	94,152	46.1%	80.3%	82.6%	79.0%	N/A
3	Transmission Overhead	Conductor	Conductor	5,056	55.4%	N/A	0.9%	0.0%	99.9%
4	Transmission Overhead	Insulator	Insulator	169,156	59.7%	100.0%	2.9%	0.0%	N/A
5	Distribution Overhead	Support Structure	Support Structures (Poles)	2,261,376	97.5%	100.0%	81.9%	80.0%	N/A
6	Distribution Overhead	Primary Overhead Conductor	Primary Overhead Conductor	1,671,801	72.9%	99.9%	N/A	N/A	100.0%
7	Distribution Overhead	Protection Device	Dynamic Protection Device	17,099	93.2%	76.8%	98.4%	63.8%	N/A
8	Distribution Overhead	Protection Device	Fuse	158,184	98.1%	34.5%	88.8%	3.2%	100.0%
9	Distribution Overhead	Protection Device	Surge Arrestor	40,278	91.7%	84.8%	N/A	N/A	N/A
10	Distribution Overhead	Voltage Regulating Equipment	Capacitor Bank	11,135	98.8%	41.5%	41.4%	20.2%	100.0%
11	Distribution Overhead	Voltage Regulating Equipment	Voltage Regulator	7,267	94.7%	71.2%	100.0%	66.6%	100.0%
12	Distribution Overhead	Transformer	Service Transformer	1,023,270	99.2%	56.2%	99.7%	76.7%	99.9%
Date Compiled:		January 18, 2023	**TOTALS**	**5,483,293**	**88.1%**	**89.2%**	**83.1%**	**71.5%**	**100.0%**

Table PG&E-22-33-2 provides an overview of Asset Data Management Programs associated with Asset Record Backlog Reduction and Asset Data Governance

TABLE PG&E-22-33-2:
ASSET DATA MANAGEMENT PROGRAMS

Data Quality Programs	ID[(a)]	Description	Progress	Timeline	Qual/ Quan
Asset Backlog Reduction: Map Correction Program	n/a	The Map Correction program is one of PG&E's primary mechanisms to field validate and improve its asset inventory data. Map Corrections are initiated and processed to correct or update the electric asset inventory data through Request for Work (RW) notification filed by front line workers, mappers and other personnel who identify discrepancies between the asset in the field and its representation in PG&E's asset inventory database.	The Map Correction program is an ongoing effort to improve the quality of data in the Asset Registry. Therefore, it does not have a target end date. In 2022, PG&E processed >260k Map Corrections. PG&E has undertaken a Map Correction process continuous improvement (Kaizen) project to improve cycles time in 2023.	Ongoing 12/2023 for targeted process improvement	Qual
Asset Backlog Reduction: As-Built Program	n/a	The As-Built program is designed to ensure timely and accurate updates to the Asset Registry for installed, replaced, removed, relocated and abandoned equipment.	The As-built program has defined four workstreams through which process maturity will continue. These are: (1) Metrics, Analytics, and Processing, (2) As-built Process Improvement, (3) As-built Guidance Documentation and Education and (4) As-built Technology and Data Improvement. Significant accomplishments in 2022 include (1) identifying and implementing process improvement ideas that emerged from mapping over 10k aged orders, (2) The establishment of a As-built Governance Process and committee, and (3) acquiring funding for the development of a mobile, digital job package app for the Undergrounding Program.	2022, 2023+	Quan/ Qual

TABLE PG&E-22-33-2:
ASSET DATA MANAGEMENT PROGRAMS
(CONTINUED)

Data Quality Programs	ID[a]	Description	Progress	Timeline	Qual/ Quan
Asset Data Governance: Enterprise Data Management Program (Organization)	n/a	Chief Data and Analytics Officer and centralized Enterprise Data Management program established in 2022. Objectives include establishing enterprise standards, tools, processes, and programs to improve data management practices across functional areas within PG&E and to systematically identify critical data, capture metadata, develop and apply data quality rules and measure progress in improving data quality.	A scalable, standardized approach to critical asset data governance, quality, and metadata management has been created and documented. (Asset Registry Data Quality program) Developing executive-level data quality KPIs and establishing baseline and targets for 2023. Employee team will be further expanded in 2023.	Ongoing	Qual
Asset Data Governance: Asset Registry Standard	n/a	The Asset Registry Standard was developed in 2022 to define an asset registry management system and associated governance requirements to provide organizational clarity, direction, and processes required to ensure accessible, high-quality asset inventory data to support asset lifecycle management processes.	Asset Registry Standard (TD-9212S) published in September 2022. Q1 2023 – Gap analysis and implementation plan development with Asset Family Owners and system stakeholders. Q4 2023 – Develop and publish the Asset Registry Procedure (TD-9212P). This procedure addresses requirements to implement changes to the Asset Registry (e.g., add new Asset Family, Asset Class, or otherwise change the data model).	Q4 2023	Qual
Asset Data Governance: Electric Data Governance Forum	n/a	Monthly forum to operationalize Electric Data Governance to systematically prioritize and effectively address asset data governance issues with involvement from affected stakeholders.	Monthly forum established. Complete.	2022 Ongoing	Qual
Asset Data Governance: Distribution/Transmission Record & Attribute Synchronization	197	This program seeks to monitor, identify and resolve emergent discrepancies for asset records and critical asset attribute fields where differences exist between data stored in core Asset Inventory (GIS) and Condition (SAP) databases.	The program implements weekly error reporting to diagnose and guide the repair of emergent data synchronization issues and generates projects to close gaps where they exist.	Ongoing	Qual

TABLE PG&E-22-33-2:
ASSET DATA MANAGEMENT PROGRAMS
(CONTINUED)

Data Quality Programs	ID[(a)]	Description	Progress	Timeline	Qual/ Quan
Asset Data Governance: Asset Registry Data Quality (ARDQ) -Improvement Initiative	n/a	PG&E instituted this program in 2022 to identify Critical Data Elements (CDE) for electric asset related data on a risk prioritized basis, establish Business Data Stewards (BDSs) and define/apply data quality rules to systematically measure the quality of its critical data. The program will be used to identify critical data quality gaps for remediation projects and track progress on those projects.	2022 Accomplishments: • Asset types/components: 13 • CDEs: 573 • Data Quality Rules implemented: 1,646 • Data Quality Values Checked: 1.2B+ • 2023 Targets: – Establish regular review cycle for Business Data Stewards/SMEs to review quality of critical data – Improve Install Date Completeness; additional asset types will be added on risk prioritized basis.	Ongoing	Both

(a) Listed ID numbers derive from the AKM Portfolio Master Inventory Tracker.

Table PG&E-22-33-3 lists projects underway to fill data gaps in PG&E's asset inventory database.[223]

TABLE PG&E-22-33-3:
IN-PROGRESS ASSET DATA QUALITY PROJECTS

In-Progress Data Quality Projects	Tracking ID	Description	Asset Type	Critical Data Element	DQ Dimension Impacted	Phase	Timeline	Qual/Quan
Distribution Secondary Overhead Type and Trace	196	Improve secondary tracing and conductor type data in asset inventory database (GIS) for wildfire areas.	Secondary Conductor	Conductor Type, Circuit ID	Completeness, Accuracy	Build	Q3 2023	Quan
Distribution Idle Facilities Mapping	208	Correctly identify and assign idle facility status to assets in wildfire and non-wildfire areas.	Transformer, Conductor	Conductor Status, Facility Status	Completeness, Accuracy	Initiate -50% complete	Q2 2023	Quan/ Qual
Distribution Primary Structure Manual Conflation	80	Improve spatial accuracy of Distribution Primary Poles in asset inventory database (GIS) within wildfire areas.	Support Structure	Location	Accuracy	Build – 75%	Q2 2023	Qual
Customer-Owned Poles with Mis-Attributed Ownership	263	Perform desktop review of 1876 poles that were identified as having a high likelihood that they are mis-attributed as customer-owned when they are PGE owned. Update ownership in GIS for those confirmed.	Support Structure	Ownership	Completeness, Accuracy	Initiate 25%	Q2 2023	Qual

223 Supplemental tables are used for individual projects reporting quantities of data too large for the primary table.

TABLE PG&E-22-33-3:
IN-PROGRESS ASSET DATA QUALITY PROJECTS
(CONTINUED)

In-Progress Data Quality Projects	Tracking ID	Description	Asset Type	Critical Data Element	DQ Dimension Impacted	Phase	Timeline	Qual/Quan
Pole Test & Treat New pole installations/dates deleted/reverted by GIS sync	249	Address ~800 asset inventory support structure records that were identified where it appears that GIS install date records conflict with data gathered by Pole Test & Treat team.	Support Structure	Installation Date	Completeness, Accuracy	Intake	Q4 2023	Qual
Distribution Underbuild	193	Identify electric distribution underbuild structures on PGE owned transmission structures and link them in distribution (EDGIS) and transmission (ETGIS) asset inventory databases.	Support Structure	Links in ET and ED GIS	Completeness, Accuracy	Build	Q4 2023	Quan/ Qual

TABLE PG&E-22-33-3:
IN-PROGRESS ASSET DATA QUALITY PROJECTS
(CONTINUED)

In-Progress Data Quality Projects	Tracking ID	Description	Asset Type	Critical Data Element	DQ Dimension Impacted	Phase	Timeline	Qual/Quan
T-Line Critical Component Asset Registry enhancements (AIC)	23	Develop capability in Asset Inventory system (ETGIS) to house new transmission critical component data to enable risk analysis and asset management	New Transmission Components - 41	Defined Critical Attributes ~ 300	Completeness, Accuracy	Plan - 10% complete	Q2 2023	Quan/ Qual
Transmission AFL Build 2022 (AIC) (See supplemental discussion below)	180	Asset Feature List (AFL) Build workstream within the Asset Information Collection multi-year project aims to collect critical component data in non-wildfire areas for transmission assets, build conservative assumption	Transmission Components, Support Structure	Nine component groups with 47 components as defined in transmission line critical component grouping white paper. See Supplemental Table YY.1.	Completeness, Accuracy	Plan	2026	Quan

TABLE PG&E-22-33-3:
IN-PROGRESS ASSET DATA QUALITY PROJECTS
(CONTINUED)

In-Progress Data Quality Projects	Tracking ID	Description	Asset Type	Critical Data Element	DQ Dimension Impacted	Phase	Timeline	Qual/Quan
		logic where data is unavailable, and inform useful life calculations.						
Wildfire Risk Modeling - Tx Composite Model input data pole type issues	152	For some poles in the transmission asset inventory database (ETGIS), the pole material type does not match with the most recent inspection record. This project seeks to identify the correct pole material type and update ETGIS if it is incorrect to enhance wildfire risk modeling.	Support Structure	Material Type (pole type)	Completeness, Accuracy	Deliver – 70% complete	Q3 2023	Qual
2020 Fire Hardening Rebuild	Pending ID	This project aims to fill data gaps in asset inventory	Multiple	Multiple	Completeness	Plan	Q3 2023	Quan

TABLE PG&E-22-33-3:
IN-PROGRESS ASSET DATA QUALITY PROJECTS
(CONTINUED)

In-Progress Data Quality Projects	Tracking ID	Description	Asset Type	Critical Data Element	DQ Dimension Impacted	Phase	Timeline	Qual/Quan
		relating to the 2020 fire hardening rebuild.						
Substation Asset Registry conflation (inside fence)	73	Data collection effort to improve accuracy of existing asset inventory within substation fence-lines.	Support Structures	As Defined by Asset Strategy	Completeness	Plan	Q4 2024	Qual
Paradise Magalia Rebuild	226	This project aims to fill data gaps in asset inventory relating to the Paradise Magalia rebuild.	Multiple	Multiple	Completeness, Accuracy, Synchronization	Build	Q4 2023	Quan
Distribution Asset Record Synchronization	197	Electric System Inspections rely on SAP records and attributes to be complete and accurate, but data in GIS that is needed by	Transformer	Feature/asset record sync	Completeness, Synchronization	Build – 56%	Q2 2023	Quan

TABLE PG&E-22-33-3:
IN-PROGRESS ASSET DATA QUALITY PROJECTS
(CONTINUED)

In-Progress Data Quality Projects	Tracking ID	Description	Asset Type	Critical Data Element	DQ Dimension Impacted	Phase	Timeline	Qual/Quan
		System Inspections in SAP is not fully synchronized. Project outcome is to ensure all required M2 distribution features are synchronized and subsequently maintained via weekly programmatic maintenance and updates.						
Transmission Asset Record Synchronization	197	Electric System Inspections rely on SAP records and attributes to be complete and accurate, but data in GIS that is needed by System Inspections in SAP is not fully synchronized.	Conductor, Support Structure	Feature/asset record sync	Completeness, Synchronization	Build – 0%	Q2 2023	Quan

TABLE PG&E-22-33-3:
IN-PROGRESS ASSET DATA QUALITY PROJECTS
(CONTINUED)

In-Progress Data Quality Projects	Tracking ID	Description	Asset Type	Critical Data Element	DQ Dimension Impacted	Phase	Timeline	Qual/Quan
		Project outcome is to ensure all required M2 transmission features are synchronized and subsequently maintained via weekly programmatic maintenance and updates.						
Distribution Asset Attribute Synchronization	197	Electric System Inspections rely on SAP records and attributes to be complete and accurate, but data in GIS that is needed by System Inspections in SAP is not fully synchronized. Project outcome is to ensure all required M3 distribution	Support Structure	DISTRIBUTIONMAP INSTALLATIONDATE INSTALLATIONJOBNUMBER CUSTOMEROWNED	Completeness, Synchronization	Build – 0%	Q2 2023	Quan

TABLE PG&E-22-33-3:
IN-PROGRESS ASSET DATA QUALITY PROJECTS
(CONTINUED)

In-Progress Data Quality Projects	Tracking ID	Description	Asset Type	Critical Data Element	DQ Dimension Impacted	Phase	Timeline	Qual/Quan
		support structure attributes are synchronized and subsequently maintained via weekly programmatic maintenance and updates.						
Transmission Asset Attribute Synchronization	197	Electric System Inspections rely on SAP records and attributes to be complete and accurate, but data in GIS that is needed by System Inspections in SAP is not fully synchronized. Project outcome is to ensure all required M3 transmission support structure attributes are	Support Structure	GIS_LAT GIS_LONG HFRA HFTD INSTALLED_DT OBJECT_ TYPE REPLACE_ EQUIP_ID SAP_EQUIP_ID SAP_FUNC_LOC_NO SAP_STRUCTURE_NO STATUS STRUCTURE_TYPE WORKCENTER POLE_	Completeness, Synchronization	Build – 0%	Q2 2023	Quan

TABLE PG&E-22-33-3:
IN-PROGRESS ASSET DATA QUALITY PROJECTS
(CONTINUED)

In-Progress Data Quality Projects	Tracking ID	Description	Asset Type	Critical Data Element	DQ Dimension Impacted	Phase	Timeline	Qual/Quan
		synchronized and subsequently maintained via weekly programmatic maintenance and updates.		CLASS				

SUPPLEMENTAL TABLE PG&E-22-33-4:
ID 180, TRANSMISSION AFL BUILD 2022 (AIC)

Component Group	Component
Conductor Group	Conductor
Conductor Group	Jumper
Conductor Group	Shield Wire
Conductor Group	OPG W
Conductor Group	Armor Rod
Conductor Group	ADS 5
Conductor Group	Aviation Ball
Conductor Group	Smart Grid Device
Insulator Group	Insulator
Insulator Group	Flying Bell
Insulator Group	Grading Ring
Non-Steel Structure Group	Non-Steel Structure
Non-Steel Structure Group	Cross Arm – Replacement (wood)
Non-Steel Structure Group	Obstruction Light (wood)
Non-Steel Structure Group	Boardwalk (wood)
Non-Steel Structure Group	Bird & Animal Guard (NS S)
Steel Structure Group	Steel Structure
Steel Structure Group	Structure – Replacement Leg Member
Steel Structure Group	Structure – Replacement Non-Leg Member
Steel Structure Group	Structure – Replacement Cross Arm (steel)
Steel Structure Group	Obstruction Light (steel)
Steel Structure Group	Boardwalk (steel)
Steel Structure Group	Bird & Animal Guard (steel)
Foundation Group	Foundation
Foundation Group	Stub Angle
Foundation Group	Anchor Bolt (TSP anchor bolts)
Switch Group	Switch
Switch Group	Distribution Equipment
Switch Group	Switch Insulator
Switch Group	PT
Switch Group	Contact-Live Parts
Switch Group	Quick Break Attachment

SUPPLEMENTAL TABLE PG&E-22-33-4:
ID 180, TRANSMISSION AFL BUILD 2022 (AIC)
(CONTINUED)

Component Group	Component
Switch Group	Interrupter
Switch Group	Battery
Switch Group	Operating Assembly
Hardware Type (Above Grade) Group	Ground Wire (NSS)
Hardware Type (Above Grade) Group	Bridging (NSS)
Hardware Type (Above Grade) Group	Guy System (NSS)
Hardware Type (Above Grade) Group	Bond Wire (NSS)
Hardware Type (Above Grade) Group	Hot-End Hardware (Insulator)
Hardware Type (Above Grade) Group	Cold-End Hardware (Insulator)
Hardware Type (Above Grade) Group	Damper (Conductor)
Hardware Type (Above Grade) Group	Spacer (Conductor)
Hardware Type (Above Grade) Group	Ground Wire (SS)
Hardware Type (Above Grade) Group	Guy System (SS)
Hardware Type (Above Grade) Group	Anchor System (SS)
Hardware Type (Above Grade) Group	Anchor System (NSS)
Hardware Type (Above Grade) Group	Connector (Conductor)
Hardware Type (Above Grade) Group	Clamp (Conductor)
Hardware Type (Above Grade) Group	Shoe Assembly (Conductor)
Hardware Type (Above Grade) Group	Tie Wire (Conductor)
Hardware Type (Above Grade) Group	Shield Wire Plate (Conductor)
Hardware Type (Above Grade) Group	Hanger Plate (SS)
Hardware Type (Above Grade) Group	Bolt (Structures)
Hardware Type (Below Grade) Group	Ground Wire (NSS)
Hardware Type (Below Grade) Group	Guy System (NSS)
Hardware Type (Below Grade) Group	Ground Wire (SS)
Hardware Type (Below Grade) Group	Guy System (SS)
Hardware Type (Below Grade) Group	Anchor System (SS)
Hardware Type (Below Grade) Group	Anchor System (NSS)
Splice Type Group	Splice

In addition to the programs and projects in-progress, Supplemental Table PG&E-22-33-5 below lists the projects PG&E completed in 2022 to improve the quality of our asset inventory database.[224]

SUPPLEMENTAL TABLE PG&E-22-33-5:
DATA QUALITY PROJECTS COMPLETED IN 2022

Data Quality Projects – Completed in 2022	Tracking ID	Description	Asset Type	Data Field	Data Improvement
Support Structure Asset Record Synchronization	131	Distribution (Dx) and Transmission (Tx) Support OH Support Structures asset record synchronization between core asset inventory (GIS) and asset condition (SAP) databases.	Transmission & Distribution Support Structure	Record, Attribute	Achieving 100% synchronization between SAP & GIS
Wood Poles in Wildfire Area Substations	139	Identified and integrated wood pole Assets in WF substations into electric Asset Inventory database (GIS).	Support Structure	Record, Attribute	100% (Of known missing HFTD pole records)
Pole Test & Treat – Pole age data corrections	44	Bulk upload pole installation date data from Pole Test & Treat program into asset inventory database (ETGIS) where data is missing.	Transmission Support Structure	See Supplemental Table PG&E-22-33-6 below	See Supplemental Table PG&E-22-33-6
ETGIS data corrections based on QC rules	45	Original scope established QC rules which have been implemented. Remediation has yet to begin but will begin by identifying assets that do not meet rules, identify and eliminate bad data, replace data when actual is known. Will complete by applying QC rules to pole height, component install date data.	Multiple	Pole Height, Installation Date	QC Rules: 100% Remediation: TBD
Pole Test & Treat Records – Audit 434	135	Installation Dates between asset inventory database (GIS) and asset condition database (SAP) do not match. Synchronize EDGIS and SAP and remove “default date” of 1/1/1990 for in SAP and replace with “null” value.	Support Structure	Installation Date	100%
Customer Owned – Poles Phase 2	160	Enhance the GIS-to-SAP interface to send customer-owned poles with PGE equipment to SAP so that they can be included in inspection planning.	Support Structure	Ownership	100%

224 Supplemental tables are used for individual projects reporting quantities of data too large for the primary table.

TABLE PG&E-22-33-5:
DATA QUALITY PROJECTS COMPLETED IN 2022
(CONTINUED)

Data Quality Projects – Completed in 2022	Tracking ID	Description	Asset Type	Data Field	Data Improvement
Transmission AFL Build 2022 (AIC)	180	Asset Feature List (AFL) Build workstream within Asset Information Collection) AIC multi-year project to collect critical component data in WF areas for transmission assets, build conservative assumptions, and develop useful life calculations. In 2022, data collection for HFTD completed. Data will be uploaded into ETGIS and improvement metrics calculated once upload is complete.	Transmission Component & Support Structure	Nine component groups with 47 components as defined in transmission line critical component grouping white paper. See Supplemental Table PG&E-22-33-6	Improvement metrics will be calculated once upload is complete.
As-Built Backlog	297	Processed all aging ED As-Built records [10,134] for orders reflecting construction completed prior to 2021.	All ED GIS Asset Registry	All ED GIS Asset Registry	100%
Map Corrections Backlog	298	Processed backlog of priority map corrections [23,216 of 25,330].	All	All	91.7%
Asset Registry Geospatial Improvements	299	Leverage LiDAR and other remote sensing data to confirm and/ improve the geospatial location of structure and conduct data for wildfire related assets. Identify missing assets.	Primary Distribution Support Structure	Location	95% of all wildfire support structure (100% of structures with LiDAR data)
M1 Synchronization	197	Find records created in GIS that failed to create in SAP and fix errors and create them in SAP.	All	All	Ongoing

SUPPLEMENTAL TABLE PG&E-22-33-6:
ID 42, PT&T AGE DATA CORRECTIONS

System	Destination Class	Destination Characteristic	Updates	Table Records	Improvement
SAP	ETL.POLE	POLE_CLASS	24435	118756	20.6%
SAP	ETL.POLE	HEIGHT_GL	18914	118756	16%
SAP	ETL.POLE	FACTORY_LENGTH	19343	118756	16.3%
SAP	ETL.POLE	MFR	48516	118756	41%
SAP	ETL.POLE	MFR_YR	51583	118756	43.4%
SAP	ETL.POLE	SPECIES_MATERIAL	23889	118756	20.1%
EDGIS	ETGIS.PoleInfo	POLE_CLASS	24435	118756	20.6%
EDGIS	ETGIS.PoleInfo	LENGTH_CLASS_AORE	24435	118756	20.6%
EDGIS	ETGIS.PoleInfo	POLE_HEIGHT	18914	118756	15.9%
EDGIS	ETGIS.PoleStructure	HEIGHT_GL	18914	112478	16.8%
EDGIS	ETGIS.PoleStructure	POLE_HEIGHT	18914	112478	16.8%
EDGIS	ETGIS.PoleInfo	FACTORY_LENGTH	19343	118756	16.3%
EDGIS	ETGIS.PoleInfo	LENGTH_CLASS_AORE	19343	118756	16.3%
EDGIS	ETGIS.PoleInfo	MANUFACTURER	48516	118756	40.9%
EDGIS	ETGIS.PoleInfo	MANUFACTURER_DT	51583	118756	43.4%
EDGIS	ETGIS.PoleInfo	AORE_MANUFACTURED_YR	51583	118756	43.4%
EDGIS	ETGIS.PoleInfo	SPECIES_MATERIAL	23889	118756	20.1%

PACIFIC GAS AND ELECTRIC COMPANY

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APPENDIX G

ALL OTHER SUPPORTING DOCUMENTATION

Appendix G – All Other Supporting Documentation

The table below consists of all attachments containing supporting documentation. Attachments will be made available on PG&E's 2023 Wildfire Mitigation Plan website.

**TABLE PG&E-G-1:
OTHER SUPPORTING DOCUMENTATION**

Attachment Name	Brief Description
2023-03-27_PGE_2023_WMP_R1_Section 6.4.2_Atch01	Circuit Segment Level Workpaper
2023-03-27_PGE_2023_WMP_R0_Section 6.6.1_Atch01	E3 Review of PG&E's Wildfire Risk Model Version 3
2023-03-27_PGE_2023_WMP_R0_Section 8.2.3_Atch01_CONF	Targeted Tree Study (Confidential)
2023-03-27_PGE_2023_WMP_R0_Section 8.3.3_Atch01	Location of Early Fault Detection, Distribution Fault Anticipation, and Line Sensor enabled circuits.
2023-03-27_PGE_2023_WMP_R0_Section 10_Atch01	Relevant portions of Wildfire Risk Governance Committee Presentation, March 2, 2022
2023-03-27_PGE_2023_WMP_R0_Section 10_Atch02_CONF	Relevant portions of Wildfire Risk Governance Committee Presentation, June 6th, 2022 (Confidential)
2023-03-27_PGE_2023_WMP_R1_Appendix C_Atch01	Geospatial Database (zip file) of Map Layers referenced in Sections 5, 6, and 9
2023-03-27_PGE_2023_WMP_R0_Appendix D ACI PG&E-22-11_Atch01	Joint IOU Covered Conductor Working Group Report
2023-03-27_PGE_2023_WMP_R0_Appendix D ACI PG&E-22-11_Atch02	PG&E Covered Conductor Testing: Phase 2 Report
2023-03-27_PGE_2023_WMP_R1_Appendix D ACI PG&E-22-16_Atch01_CONF	PG&E's 2023-2026 Undergrounding Workplan (Confidential)
2023-03-27_PGE_2023_WMP_R0_Appendix D ACI PG&E-22-32_Atch01_CONF	2022 Reliability Study (Confidential)

PACIFIC GAS AND ELECTRIC COMPANY

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APPENDIX H

LIST OF ACRONYMS AND ABBREVIATIONS

Appendix H – List of Acronyms and Abbreviations

TABLE PG&E-H-1
LIST OF ACRONYMS AND ABBREVIATIONS

Acronym	Term/Definition
°F	degrees Fahrenheit
A.	Application
AAR	After Action Review
AB	Assembly Bill
ACE	Apparent Cause Evaluation
ACI	Areas for Continued Improvement
ACS	American Community Survey
ACSR	Aluminum Conductor Steel Reinforced
ADS	Atmospheric Data Solutions
AFL	Asset Feature List
AFN	Access and Functional Needs
AGA	American Gas Association
AGL	Above Ground Level
AI	Artificial Intelligence
AIC	Asset Information Collection
AKM	Asset Knowledge Management
AL	Advice Letter
ALJ	Administrative Law Judge
ALM	Application Life Cycle Management
ALP	Apprenticeship Line Program
AMP	Asset Management Plans
AMPS	Asset Management Platform and Services
ANSI	American National Standards Institute
AOC	Area of Concern
API	Application Programming Interface
AQL	Acceptable Quality Levels
ARC	Annual Report on Compliance
ARDQ	Asset Registry Data Quality
ASL	American Sign Language
ATLAS	Application Technology Lifecycle and Systems
ATS	Applied Technology Services

TABLE PG&E-H-1
LIST OF ACRONYMS AND ABBREVIATIONS
(CONTINUED)

Acronym	Term/Definition
ATSDR	Agency for Toxic Substances and Disease Registry
AUC	Area Under the Curve
AWRR	Accelerated Wildfire Risk Reduction
AWS	Amazon Web Services
BLM	Bureau of Land Management
BMP	Best Management Practice
BPTM	Backup Power Transfer Meter
BTM	Behind-The-Meter
BTU	British Thermal Unit
BVLOS	Beyond Visual Line of Sight
CAIDI	Customer Average Interruption Duration Index
CAL FIRE	California Department of Forestry and Fire Protection
Cal OES	California Governor’s Office of Emergency Services
CALVEG	Classification and Assessment with Landsat of Visible Ecological Groupings
CAP	Corrective Action Program
CARE	California Alternate Rate for Energy
CBO	Community-Based Organization
CC	Covered Conductor
CCA	Community Choice Aggregators
CCE	Common Cause Evaluation
CCR	California Code of Regulations
CDAO	Chief Data and Analytics Officer
CDC	Centers for Disease Control and Prevention
CDE	Critical Data Element
CDEC	California Data Exchange Center
CEMI	Customers Experiencing Multiple Interruptions
CERP	Company Emergency Response Plan
CESO	Customers Experiencing a Sustained Outage
CFB	Catastrophic Fire Behavior
cFCI	Communicating Faulted Circuit Indicator
CFI	Critical Facility and Infrastructure
CFP	Catastrophic Fire Probability
CGS	California Geological Survey
CHSC	Chaparral and Serotinous Conifers

TABLE PG&E-H-1
LIST OF ACRONYMS AND ABBREVIATIONS
(CONTINUED)

Acronym	Term/Definition
CIL	Critical Infrastructure Lead
CL	Confidence Level
CMDB	Configuration Management Database
CMEP	Community Microgrid Enablement Program
CMI	Customer Minutes Interrupted
COL	Conclusion of Law
CoRE	Consequence of Risk Event
COSC	Coastal Sage Scrub
COVID-19	Coronavirus disease of 2019
CPG	Comprehensive Preparedness Guide
CPUC or Commission	California Public Utilities Commission
CPZ	Circuit Protection Zone
CRC	Community Resource Centers
CRESS	Corporate Real Estate Strategy and Services
CRT	Constraints Resolution Team
CSM	Clean Substation Microgrid
CSU	California State University
CUEA	California Utilities Emergency Association
CWSP	Community Wildfire Safety Program
D.	Decision
DAC-AG	Disadvantaged Communities Advisory Group
DAHS	Distribution Asset Health Specialist
DASH	Dynamic Automated Seismic Hazard
DCC	Distribution Control Center
DCD	Downed Conductor Detection
DDAR	Disability Disaster Access and Resources
DEM	Digital Elevation Mode
DER	Distributed Energy Resource
DFA	Distribution Fault Anticipation
DFM	Dead Fuel Moisture
DMCO	Dry Mixed Conifer
DMS	Distribution Management System
DOI	Department of the Interior
DRPP	Distribution Routine Patrol Procedure

TABLE PG&E-H-1
LIST OF ACRONYMS AND ABBREVIATIONS
(CONTINUED)

Acronym	Term/Definition
DTS-FAST	Distribution, Transmission, and Substation: Fire Action Schemes and Technology
DX	Distribution
EBMUD	East Bay Municipal Utility District
EC	Electric Corrective
EC	Emergency Operations Center Commander
ECCVM	Event Classification Through Current and Voltage Monitoring Sensors
EDEC	Electric Distribution Emergency Center
EDGIS	Electric Distribution Geographic Information System
EDMP	Enterprise Data Management Program
EDPM	Electric Distribution Preventive Maintenance
EDPM	Electric Distribution Procedure Manual
EEI	Edison Electric Institute
EF	Equivalent Fatalities
EFD	Early Fault Detection
EIA	Enhanced Ignition Analysis
EII	Electrical Incident Investigation
EIR	Electric Incident Reports
EN	European Norm
EO	Electric Operations
EOC	Emergency Operations Center
EORM	Enterprise and Operational Risk Management
EOY	End of Year
EP&R	Emergency Preparedness and Response
EPC	Engineering, Procurement, and Construction
EPIC	Electric Program Investment Charge
EPRI	Electric Power Research Institute
EPSS	Enhanced Powerline Safety Settings
ERM	Enterprise Risk Model
ERTC	Environmental Release to Construction
ESA	Energy Savings Assistance
ESGIS	Electric Substation Geographic Information System
ESJ	Environmental and Social Justice
ESRB	Electric Safety and Reliability Branch

TABLE PG&E-H-1
LIST OF ACRONYMS AND ABBREVIATIONS
(CONTINUED)

Acronym	Term/Definition
ET	Electric Transmission
ETEC	Electric Transmission Emergency Center
ETGIS	Electric Transmission Geographic Information System
ETL	Electric Transmission Line
ETOR	Estimated Time of Restoration
ETPM	Electric Transmission Preventive Maintenance
EV	Expected Value
EVEG	Existing Vegetation Geodatabase (USFS geodatabase)
EVM	Enhanced Vegetation Management
F&A	Finance and Administration
FAA	Federal Aviation Administration
FAC	Federal Agency Code
FAN	Field Area Network
FBI	Fire Behavior Index
FDA	Facility Damage Action
FE	Functional Exercise
FEA	Finite Element Analysis
FEMA	Federal Emergency Management Agency
FERA	Family Electric Rate Assistance
FERC	Federal Energy Regulatory Commission
FGDB	File Geodatabase
FIA	Fire Index Area
FIRESCOPE	Firefighting Resources of California Organized for Potential Emergencies
FMEA	Failure Modes and Effects Analysis
FORCE	Field Operations Resource Calculation of Estimated Time of Restoration
FPI	Fire Potential Index
FPS	Fixed Power Solutions
FQC	Field Quality Control
FQCPM	Field Quality Control Program Manager
FRI	Fire Return Interval
FRID	Fire Return Interval Departure
FSE	Full-Scale Exercise
FSR	Field Safety Reassessment
ft.	foot/feet

TABLE PG&E-H-1
LIST OF ACRONYMS AND ABBREVIATIONS
(CONTINUED)

Acronym	Term/Definition
FTE	Full-Time Employee
FTE	Full-Time Equivalent
GC	General Construction
GE	General Electric Company
GEC	Gas Emergency Center
GED	General Educational Development Test
GHG	Greenhouse Gases
GIS	Geographic Information System
GO	General Order
GRC	General Rate Case
GRFO	Grasses and Forbes
HAWC	Hazard Awareness and Warning Center
HCP	Habitat Conservation Plan
HFRA	High Fire Risk Area
HFTD	High Fire Threat District
HR	Human Resources
HSEEP	Homeland Security Exercise Evaluation Program
HUD	Housing and Urban Development
HWW	High Wind Warning
I&I	Intelligence and Investigation
IAP	Incident Action Plan
IBEW	International Brotherhood of Electrical Workers
IC	Incident Commander
ICEA	Insulated Cable Engineers Association
ICS	Incident Command System
IFIR	Insufficient Fire Regime Information
IHSS	In-Home Support Services
ILC	Independent Living Centers
IM	Instruction Memorandum
IMT	Incident Management Teams
iOS	IDevice Operating System
IOU	Investor-Owned Utility
IPW	Ignition Probability Weather
IQA	Image Quality Assurance

TABLE PG&E-H-1
LIST OF ACRONYMS AND ABBREVIATIONS
(CONTINUED)

Acronym	Term/Definition
IR	Infrared
ISA	International Society of Arboriculture
ISO	International Organization for Standardization
IT	Information Technology
IVM	Integrated Vegetation Management
IVR	Interactive Voice Recording
JATC	Joint Apprentice and Training Committee
JIS	Joint Information Systems
JIT	Just-in-Time
Km.	Kilometer
kV	Kilovolt
kV/in	kilovolts per inch
LBGIS	Landbase Geographic Information System
LEP	Limited English Proficiency
LFM	Live Fuel Moisture
LiDAR	Light Detection and Ranging
LIMA	Limited Area
LNO	Liaison Officers
LOB	Line of Business
LoRE	Likelihood of a Risk Event
LR	Line Reclosers
LRQA	Lloyd’s Register
M&C	Maintenance and Construction
m.	meter
MAA	Mutual Assistance Agreement
MADIS	Meteorological Assimilation Data Ingest System
MAVF	Multi-Attribute Value Function
MBA	Master of Business Administration
MBL	Medical Baseline
MCMI	Million Customer Minutes Interrupted
MDR	Minimum Distance Requirement
MEA	MyElectronicAccess
MED	Major Event Days
MIEV	Mixed Evergreen

TABLE PG&E-H-1
LIST OF ACRONYMS AND ABBREVIATIONS
(CONTINUED)

Acronym	Term/Definition
MIP	Microgrid Incentive Program
ML	Machine Learning
MMCO	Moist Mixed Conifer
MOA	Memorandum of Agreement
MOCH	Montane Chaparral
MOR	Multi Outage Review
MSO	Motorized Switch Operator
MYNN	Mellor Yamada Nakanishi-Niino
MYTEP	Multi-Year Training and Exercise Plan
NECA	National Electrical Contractors Association
NERC	North American Electric Reliability Corporation
NIMS	National Incident Management System
NMAP	Not Mapped by Existing Vegetation Geodatabase
NOAA	National Oceanic and Atmospheric Administration
NOD	Notice of Defect
NOV	Notice of Violation
NPFR	No Pre-Euro-American Settlement Fire Regime
NPS	National Park Service
NRM	Natural Resource Management
NTP	Near-Term Process
NWS	National Weather Service
O&M	Operations and Maintenance
O2	Oxygen Molecules
O3	Ozone
OA	Operability Assessment
OAKW	Oak Woodland
OCM	Overhead Circuit Mile
OEC	Operations Emergency Center
OEIS or Energy Safety	Office of Energy Infrastructure Safety
OES	Office of Emergency Services
OH	Overhead
OIC	Officer-in-Charge
OII	Order Instituting Investigation
OIR	Order Instituting Rulemaking

TABLE PG&E-H-1
LIST OF ACRONYMS AND ABBREVIATIONS
(CONTINUED)

Acronym	Term/Definition
OP	Ordering Paragraph
OPW	Outage Producing Wind
OSHA	Occupational Safety and Health Administration
Pf	Probability of Failure
PFR	Pre-Euro-American Settlement Fire Regime
PG	Power Generation
PG&E or the Company	Pacific Gas and Electric Company
PI	Pre-Inspection
PI/TT	Pre-Inspection/Tree Trimming
PIC	Potentially-Impacted Customers
PIH	Pre-installed Interconnection Hub
PIM	Pre-Inspection Manager
PIO	Public Information Officer
PMD	Project Management Database
PMO	Project Management Office
PMP	Project Management Professional
POL	Privately Owned Lines
POMMS	PG&E Operational Mesoscale Modeling System
PRC	Public Resources Code
PSDR	Post Season Data Report
PSIP	PSPS Situational Intelligence Platform
PSPS	Public Safety Power Shutoff
PSS	Public Safety Specialist
PT&T	Pole Test and Treat
Pub. Util. Code or PUC	Public Utilities Code
PV	Partial Voltage
PWDAAC	People with Disabilities and Aging Advisory Council
QA	Quality Assurance
QA/QC	Quality Assurance/Quality Control
QA/WV	Quality Control/Work Verification
QAVM	Quality Assurance Vegetation Management
QC	Quality Control
QCR	Qualified Company Representative
QDR	Quarterly Data Report

TABLE PG&E-H-1
LIST OF ACRONYMS AND ABBREVIATIONS
(CONTINUED)

Acronym	Term/Definition
QEW	Qualified Electrical Worker
QN	Quarterly Notification
QV	Quality Verification
QVVM	Quality Verification Vegetation Management
R&D	Research and Development
R.	Rulemaking
RAMP	Risk Assessment and Mitigation Phase
RAWS	Remote Automatic Weather Station
RBDF	Risk-Based Decision-Making Framework
RCA	Root Cause Analyses
RCAM	Redwood Coast Airport Microgrid
RCC	Risk and Compliance Committee
RCE	Root Cause Evaluations
REACH	Relief for Energy Assistance through Community Help
REC	Regional Emergency Center
REDW	Redwood
REFCL	Rapid Earth Fault Current Limiter
Res.	Resolution
RF	Radio Frequency
RFI	Request for Information
RFIR	Red Fir
RFP	Request for Proposal
RFW	Red Flag Warning
RFW OH	Red Flag Warning Overhead
RH	Relative humidity
RMWG	Risk Model Working Group
RN	Revision Notice
ROW	Right-of-Way
RPF	Registered Professional Forester
RSE	Risk Spend Efficiency
RT	Radiographic Testing
RW	Request for Work
SAP	Systems, Applications and Products
SCADA	Supervisory Control and Data Acquisition

TABLE PG&E-H-1
LIST OF ACRONYMS AND ABBREVIATIONS
(CONTINUED)

Acronym	Term/Definition
SCE	Southern California Edison Company
SDG&E	San Diego Gas & Electric Company
SE	Strategy and Execution
SEB	State Executive Briefing
SED	Safety and Enforcement Division
SEMS	Standardized Emergency Management System
SFPE	Society of Fire Protection Engineers
SGIP	Self-Generation Incentive Program
SI	System Inspection
SIPOC	Suppliers, Inputs, Processes, Outputs by Section and Customers
SIPT	Safety and Infrastructure Protection Teams
SIV	Self-Identified Vulnerable
S-MAP	Safety Model and Assessment Proceeding
SMB	Small and Medium Business
SME	Subject-Matter Expert
SNO	Safety and Nuclear Oversight
SOPP	Storm Outage Prediction Model
SPS	Standalone Power System
sq. mi.	square miles
SQL	Structured Query Language
SRA	State Responsibility Area
SUP	NPS Special Use Permits
SVI	Social Vulnerability Index
SWRSE	Simplified Wildfire Risk Spend Efficiency
T&D	Transmission and Distribution
TAHS	Transmission Asset Health Specialist
TCCI	Tree-Caused Circuit Interruption
TCM	Transmission Composite Model
TIVM	Transmission Integrated Vegetation Management
TP	Time Places
TT	Tree Trimming
TTD	Telecommunications Device for the Deaf
TTS	Targeted Tree Species
TTX	Tabletop Exercises

TABLE PG&E-H-1
LIST OF ACRONYMS AND ABBREVIATIONS
(CONTINUED)

Acronym	Term/Definition
TTY	Teletypewriter
TVM	Transmission Vegetation Management
TX	Transmission
U.S.	United States
UAT	User Acceptance Training
UCLA	University of California Los Angeles
UDS	Utility Defensible Space
UG	Underground
USFS	United States Forest Service
USGS	United States Geological Survey
VCT	Vegetation Control Technician
VGI	Vehicle Grid Integration
VIIRS	Visible Infrared Imaging Radiometer Suite
VM	Vegetation Management
VMARS	Vegetation Management Reporting and Analytic Server
VMD	Vegetation Management Database
VMI	Vegetation Management Inspector
VP	Vice President
WBT	Web Based Training
WCAG	Web Content Accessibility Guidelines
WDRM	Wildfire Distribution Risk Model
WECC	Western Electricity Coordinating Council
WEI	Western Energy Institute
WFC	Wildfire Consequence
WFE	Wildfire Feasibility Efficiency
WGE	Work Group Evaluations
WIV	Wildfire Incident Viewer
WMP	Wildfire Mitigation Plan
WMS	Work Management System
WOR	Weekly Operating Review
WRGSC	Wildfire Risk Governance Steering Committee
WRMAA	Western Regional Mutual Assistance Agreement
WRMAG	Western Region Mutual Assistance Group
WRO	Work Requested by Others

TABLE PG&E-H-1
LIST OF ACRONYMS AND ABBREVIATIONS
(CONTINUED)

Acronym	Term/Definition
WRRM	Wildfire Risk Reduction Model
WS	Wind Speed
WSD	Wildfire Safety Division
WSIP	Wildfire Safety Inspection Program
WTRM	Wildfire Transmission Risk Model
WUI	Wildland-Urban Interface
WV	Work Verification
YPIN	Yellow Pine

PACIFIC GAS AND ELECTRIC COMPANY

2023-2025 WILDFIRE MITIGATION PLAN

APPENDIX I

CONFIDENTIAL IN ITS ENTIRETY