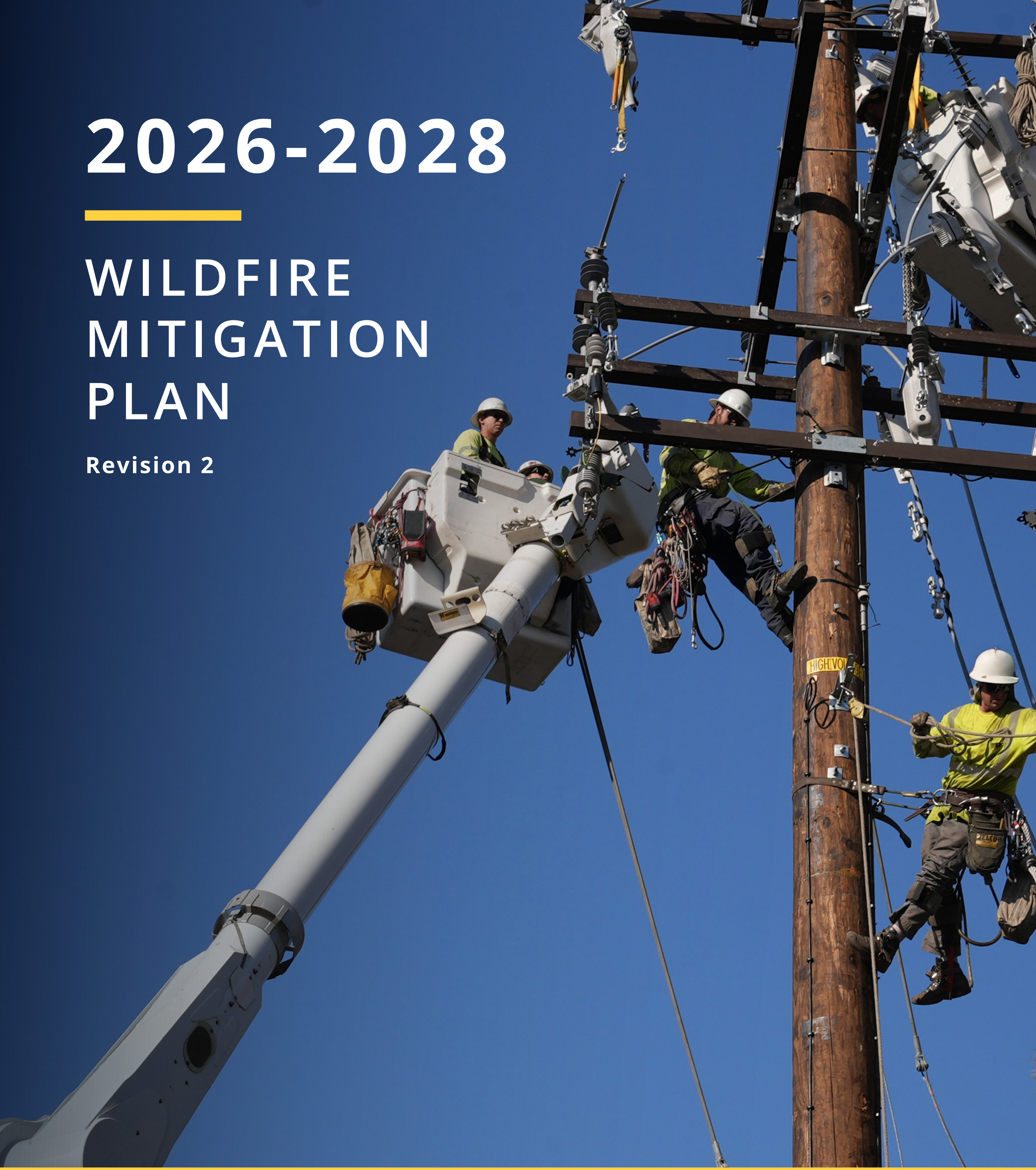

2026-2028

WILDFIRE MITIGATION PLAN

Revision 2

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

October 27, 2025

SOUTHERN CALIFORNIA EDISON®

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1 Executive Summary

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

SCE is dedicated to the safety of our customers and the communities we serve. Our 2026-2028 WMP builds upon our accomplishments and lessons learned from the 2023-2025 WMP and multiple years of proactive and industry-leading wildfire mitigation.

SCE's efforts to date include approximately 6,400 miles of covered conductor (representing approximately 70% of SCE's overhead distribution circuit miles in HFRA), extensive asset inspection and vegetation management activities that exceed state requirements, deployment of innovative hardening technologies such as Rapid Earth Fault Current Limiter (REFCL), and an expansive network of approximately 1,780 weather stations and 200 high-definition (HD) cameras that provide heightened situational awareness of risks to our system. Overall, SCE has made great strides in reducing wildfire risk across our service territory and the associated need to utilize Public Safety Power Shutoffs (PSPS) as a last resort safety measure.

We also recognize the devastating losses caused in early January 2025 by wildfires in the Los Angeles area. These events have been extremely challenging for the impacted communities, and SCE deeply appreciates the efforts of first responders and aid organizations to control the fires and support the public. SCE also wishes to extend its thanks to the frontline workers from external utilities who stepped in to begin service restoration. The wind and fuel conditions in January 2025 included hurricane-force winds and record dry conditions, demonstrating the importance of a continued statewide focus on wildfire mitigation given that extreme weather and climate change will continue these trends.

At the time of submitting this WMP in March 2025, the causes of most of the January fires remain under investigation. In instances where SCE's infrastructure is part of the investigation, SCE is cooperating with investigators.

This WMP represents SCE's continued efforts to mature and evolve its wildfire mitigation efforts, to learn from our experiences and from peers, and to develop a forward-looking strategy. We also acknowledge the hardships that PSPS had for our customers and communities during the historic wind event in January 2025. SCE is committed to minimizing the impacts of PSPS through its grid hardening efforts and customer support services detailed in this WMP. Below, SCE describes our path forward for the 2026-2028 WMP.

1.1 Primary WMP Goal

The primary goal of SCE's WMP is to reduce the risk of wildfires associated with utility equipment and to reduce the scope, scale, frequency and impacts of PSPS events.

1.2 Plan Objectives

SCE has established the following plan objectives for its 2026-2028 WMP:

1. Continue programmatic deployment of covered conductor and targeted undergrounding of distribution lines in SCE's High-Fire Risk Areas (HFRA) to reduce the likelihood that objects will contact powerlines and lead to an ignition, and to reduce the potential frequency and duration of PSPS events.
2. Continue and expand transmission hardening programs such as proactive splice shunting, enhanced design standards, and evaluation of additional approaches to address ignition drivers on the transmission system.
3. Continue execution of protection programs (e.g., Remote Earth Fault Current Limiters, Distribution Open Phase Detection (DOPD), and fast curve settings) to detect fault current and minimize ignition likelihood.
4. Execute risk-informed inspections of utility assets for the distribution and transmission system that identify, prioritize, and resolve issues that pose potential ignition sources.
5. Execute utility vegetation management programs to maintain clearances around utility lines, reducing the potential for ignitions due to vegetation contact with energized lines.
6. Maintain and enhance SCE's extensive network of weather stations, HD cameras, and associated meteorological functions to provide situational awareness to SCE and to external parties such as fire suppression agencies.
7. Provide effective and accurate communications to the public before, during, and after major outages, PSPS events, and emergencies with information and resources needed to mitigate potential safety and economic impacts.
8. Maintain a comprehensive, all-hazards planning and preparedness program to provide effective emergency response, safely and expeditiously restore service during and after a major event, and communicate effectively with customers, stakeholders, and agency partners.

1.3 Framework for the development of the Base WMP

SCE takes a portfolio approach to its WMP, developing and implementing complementary mitigations that collectively reduce the risk of utility-caused wildfires. Even foundational programs such as covered conductor cannot fully succeed on their own, as periodic activities such as asset inspections, maintenance and vegetation management must be continually executed to identify and address potential sources of wildfire risk.

SCE will continue to execute its Integrated Wildfire Mitigation Strategy (IWMS), which aligns grid hardening, asset inspections, and vegetation management activities based on a tiered prioritization of potential wildfire consequence. This approach reduces the risk of catastrophic wildfire by targeting locations based on factors such as a high frequency of past fires, limited road availability and evacuation constraints, wind and fuel conditions that exceed PSPS thresholds even after covered conductor deployment, and areas where fire spread can be rapid and large following initial ignition.

The IWMS divides SCE's HFRA based on potential customer and community impacts into three tranches of risk areas: (1) Severe Risk Areas, which represent locations with the highest risks; (2) High Consequence Areas; and (3) Other HFRA, which represent areas of lower relative risk than the first two tranches. SCE uses these risk tranches to inform preferred mitigation strategies based on risk levels and risk drivers, and to inform the frequency and locations for mitigation deployment.

Wildfire risk is not static; it changes over time due to development, fuel conditions, population movement, and other factors. Risk modeling approaches and methodologies also continue to improve, and SCE has demonstrated a commitment to regular updates to its risk analysis tools and results. In 2019, and then again in 2024, SCE was the first large utility in California to submit a proposal to the California Public Utilities Commission (CPUC) to update its high-fire risk designations within its service territory. SCE also plans to evaluate if changes to its wildfire risk models are warranted considering that the January 2025 wildfires raise important questions regarding the spread of wildfires into built urban environments.

1.4 Summary of SCE's 2026-2028 WMP

SCE summarizes the major sections of its 2026-2028 WMP below.

1.4.1 Grid Design and System Hardening

SCE is on track to substantially complete its proactive deployment of covered conductor in HFRA by 2028, with approximately 6,400 circuit miles of bare overhead distribution lines replaced since program inception in 2018. This has dramatically reduced the potential for wildfire due to the contact of foreign objects such as vegetation with power lines, while also providing improvements in service reliability and fault performance.

During this WMP period SCE is planning to replace 440 overhead circuit miles with covered conductor. Under its targeted undergrounding program, SCE is also planning to convert 260 miles of overhead distribution lines to underground lines, with a scope informed by its IWMS framework to effectively eliminate the potential for wildfire ignitions and PSPS events.

SCE also plans to continue its innovative use of REFCL technology, which, when combined with covered conductor, can achieve levels of wildfire risk reduction approaching what is achieved by undergrounding. SCE will also further develop its transmission strategies and mitigations, such as a proactive shunting replacement program, enhanced transmission construction standards to increase system robustness, and continued evaluation of additional transmission hardening mitigation costs and benefits.

1.4.2 Asset Inspections and Remediations

SCE plans to perform extensive risk-informed asset inspections that exceed state requirements by inspecting the highest-risk distribution and transmission assets annually. SCE uses ground, aerial, and other imaging technologies to detect potential issues that could lead to an ignition, which are then classified by risk and remediated accordingly. SCE continues its commitment to risk-informed and timely remediation of inspection findings. SCE also plans to continue its use of leading standards for inspection quality control and quality assurance.

1.4.3 Vegetation Management

Vegetation contact with energized power lines is a significant source of potential wildfire risk. Vegetation management is an ongoing activity SCE performs based on multiple years of successful execution. For this WMP cycle, SCE intends to continue HFRA-wide inspections of its distribution and transmission lines to maintain clearances. SCE plans to perform these inspections via a combination of ground, aerial, and imaging technology methods.

SCE will also continue to execute its hazard tree and dead and dying tree programs, which identify trees with the potential to fall into utility lines. SCE has also established targets for its structure brushing program that exceed state requirements and aim to remove vegetation material from the base of distribution and transmission structures.

1.4.4 Situational Awareness and Forecasting

SCE's portfolio of situational awareness activities provides SCE with advanced and localized meteorological data and forecasts that enable short-term decisions such as potential PSPS conditions or the need for ad-hoc asset or vegetation inspections based on heightened levels of wildfire risk. Additionally, SCE's network of HD cameras is shared with fire suppression agencies, enhancing capabilities for ignition detection and response. In this WMP, SCE describes these activities along with its fuel sampling program, weather station calibrations, and weather forecasting model updates.

SCE also plans to continue to deploy and improve grid monitoring programs including Early Fault Detection (EFD), open-phase detection for both distribution and transmission, and high-impedance fault detection, which are intended to detect and enable responses to potential fault conditions that could pose an ignition risk.

1.4.5 Emergency Preparedness, Collaboration, and Community Outreach

SCE has developed collaborative relationships with public safety agencies, community organizations, and other key stakeholders to engage in and support its wildfire mitigation activities. While we are searching for alternative funding sources, SCE's support for aerial suppression resources continues in this WMP, with the fires in January 2025 demonstrating the critical public safety value of such resources.

SCE plans to continue its use of Incident Management Team (IMT) practices consistent with industry standards, which allows SCE to effectively manage its own response to emergencies, in addition to efficient coordination with public safety agencies.

1.4.6 Public Safety Power Shutoff (PSPS)

SCE continues to consider PSPS as a measure of last resort. The weather, vegetation, and wind conditions in 2024 and into 2025 demonstrated the significant value of PSPS that must be kept as a wildfire mitigation activity despite the impacts it has for our customers. In patrols following PSPS events, SCE has found instances in which vegetation has been blown into extended contact with power lines, which may have caused an ignition if the lines were energized. PSPS events—especially at longer durations—are challenging for our customers, but the risks posed by PSPS de-energizations are outweighed by wildfire risk.

Between 2023 and 2025, SCE's service territory saw more extreme fire weather with each subsequent year, prompting an annual increase in PSPS. If current trends of extreme weather and fire conditions continue, PSPS events will continue and may increase in frequency and duration as an essential mitigation to protect public safety.

SCE remains focused on improving its customer communications before, during, and after PSPS events, and reducing the scope and duration of PSPS events through execution of hardening programs, sectionalizing, and rapid patrols to evaluate its ability to safely restore power. SCE also plans to continue customer support programs such as battery backups and portable generators to reduce the impacts of PSPS de-energizations.

1.4.7 Risk Methodology and Assessment

In this WMP, SCE describes a variety of improvements to its wildfire risk modeling techniques, such as expanding the geographic coverage of its wildfire consequence modeling and improving its use of historical fire weather days to model potential wildfire growth following ignition. SCE also discusses quasi-probabilistic modeling techniques and considerations in comparing extreme fire outcomes against probability-weighted outcomes. As noted above, in late 2024 SCE submitted a proposal to the CPUC to update its wildfire risk level boundaries based on its latest risk modeling, and SCE also plans to consider potential risk model changes based on how the January 2025 fires spread into residential areas.

1.5 Conclusion

SCE's WMP demonstrates a continued evolution of our wildfire mitigation program, and provides an integrated, risk-informed approach to continue to reduce the remaining wildfire risk and PSPS impacts in our service territory. Since 2018, SCE has substantially reduced wildfire risk by developing and implementing a comprehensive portfolio of mitigations. SCE appreciates the State's concurrent efforts to reduce the risk of catastrophic wildfires and looks forward to further action. SCE remains committed to continuing to enhance its wildfire mitigation programs to address the continued threat of catastrophic fires posed by extreme weather and climate change.

2 RESPONSIBLE PERSONS

The electrical corporation must list those responsible for executing the Base WMP, including:

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

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

Jill Anderson, Executive Vice President of Operations at SCE, has overall responsibility for this Wildfire Mitigation Plan.

The table below details the program owners with responsibility for each of the main components of the plan.

Questions related to activities described in this plan can be submitted to SCE through the following email address: wildfires@sce.com.

Table SCE 2-01: Responsible Persons

WMP Section	Title	Program Owner
1	Executive Summary	Ray Fugere, Director, Asset & System Intelligence
2	Responsible Persons	Ray Fugere, Director, Asset & System Intelligence
3	Overview of Base WMP	Ray Fugere, Director, Asset and System Intelligence Gary Chen, Director, Safety & Infrastructure Policy
4	Overview of the Service Territory	Gary Chen, Director, Safety & Infrastructure Policy
5	Risk Methodology and Assessment	Seema Turner, Director, Enterprise Risk Management & Public Safety
6	Wildfire Mitigation Strategy	Ray Fugere, Director, Asset and System Intelligence
7	Public Safety Power Shutoff	Melanie Jocelyn, Director, Business Resiliency
8.0-8.4	Grid Design and System Hardening, Asset Inspections, Equip. Maint. and Repair	Ray Fugere, Director, Asset and System Intelligence
8.5	Quality Assurance and Quality Control	Melvin Stark, Principal Manager, Compliance and Quality

WMP Section	Title	Program Owner
8.6	Work Orders	Ray Fugere, Director, Asset and System Intelligence
8.7	Grid Operations and Procedures	Andrew Swisher, Consulting Engineer, Asset Engineering
8.8	Workforce Planning	Ray Fugere, Director, Asset and System Intelligence
9	Vegetation Management and Inspections	Carter Prescott, Director, Vegetation & Land Management
10.0-10.2	Situational Awareness Targets, Environmental Monitoring Systems	Melanie Jocelyn, Director, Business Resiliency
10.3	Grid Monitoring Systems	Andrew Swisher, Consulting Engineer, Asset Engineering
10.4-10.6	Ignition Detection Systems, Weather Forecasting, Fire Potential Index	Melanie Jocelyn, Director, Business Resiliency
11	Emergency Preparedness, Collaboration, and Community Outreach Awareness	Melanie Jocelyn, Director, Business Resiliency Valarie Hernandez, Principal Manager, Customer Service
12	Enterprise Systems	Brian Taft, Principal Manager, Transmission and Distribution Portfolio Management
13	Lessons Learned	Ray Fugere, Director, Asset and System Intelligence

3 OVERVIEW OF BASE WMP

3.1 Primary Goal

Each electrical corporation must state the primary goal of its Base WMP. The primary goal must be consistent with California Public Utilities Code section 8386(a).

As stated in Chapter 1, the primary goal of our WMP is to reduce the risk of wildfires associated with utility equipment and to reduce the scope, scale, frequency and impacts of PSPS events.

In accordance with Section 8386(a) of the California Public Utilities Code, SCE constructs, maintains, and operates its electrical lines and equipment in a manner that will minimize the risk of catastrophic wildfire posed by those electrical lines and equipment.

3.2 Plan Objectives

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

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

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

Table SCE 3-01: Plan Objectives

Plan Objective	***Related Target(s)***	***Risk Drivers Addressed***	***Related Performance Metrics***
1. Continue programmatic deployment of covered conductor and targeted undergrounding of distribution lines in SCE's High-Fire Risk Areas (HFRA) to reduce the likelihood that objects will contact powerlines	SH-1, SH-2	Contact from object, vegetation contact, Equipment / facility failure or damage, wire-to-wire contact	Number of CPUC reportable ignitions in HFRA, Number of wire downs in HFRA, Number of outages in HFRA, Number of Tree-Caused Circuit Interruptions (TCCIs) in HFRA, Frequency of

Plan Objective	Related Target(s)	Risk Drivers Addressed	Related Performance Metrics
and lead to an ignition, and to reduce the potential frequency and duration of PSPS events.			Public Safety Power Shutoff (PSPS) events (total), Scope of PSPS events (total), Duration of PSPS (total)
2. Continue and expand transmission hardening programs such as proactive splice shunting, enhanced design standards, and evaluation of additional approaches to address ignition drivers on the transmission system.	SH-20, Sections 8.2.6.4, 8.2.13.1	Contact from object, vegetation contact, wire-to-wire contact, equipment/facility failure or damage	Number of CPUC reportable ignitions in HFRA, Number of wire downs in HFRA, Number of outages in HFRA
3. Continue execution of protection programs (e.g., REFCL, Distribution Open Phase Detection (DOPD), EFD, and fast curve settings) to detect fault current and minimize ignition likelihood.	SH-5, SH-17, SH-18, SA-11, SA-14, Sections 8.2.6, 8.7.1	Equipment/facility failure or damage	Number of CPUC reportable ignitions in HFRA
4. Execute risk-informed inspections of utility assets for the distribution and transmission system that identify, prioritize, and resolve issues that pose	IN-1.1, IN-1.2, IN-3, IN-4, IN-5, IN-10, IN-11, IN-12	Equipment/facility failure or damage, vegetation contact, wire-to-wire contact	Number of CPUC reportable ignitions in HFRA, Number of wire downs in HFRA, Number of outages in HFRA, Number of asset

Plan Objective	Related Target(s)	Risk Drivers Addressed	Related Performance Metrics
potential ignition sources.			management ignition risk-related work orders (excluding GO95 exceptions) that are past due
5. Execute utility vegetation management programs to maintain clearances around utility lines, reducing the potential for ignitions due to vegetation contact with energized lines.	VM-1, VM-4, VM-7, VM-8, VM-2.1, VM-2.2, VM-13	Vegetation contact	Number of CPUC reportable ignitions in HFRA, Number of wire downs in HFRA, Number of outages in HFRA, Number of Tree-Caused Circuit Interruptions in HFRA, Number of trees inspected where at least some vegetation was found in a non-compliant condition in HFRA
6. Maintain and enhance SCE's extensive network of weather stations, HD cameras, and associated meteorological functions to provide situational awareness to SCE and to external parties such as fire suppression agencies.	SA-3, SA-12, SA-13, SA-15, SA-16, SA-17, SA-18, SA-19	Does not directly reduce wildfire POI, but enables SCE to evaluate short-term conditions for wildfire and outage program risk	Duration of PSPS, Scope of PSPS events, Number of customers impacted by PSPS
7. Provide effective and accurate communications to	DEP-1, DEP-4, PSPS-2, PSPS-3, Sections 11.4, 11.5	PSPS impacts	Percentage of customer recall of SCE wildfire and

Plan Objective	Related Target(s)	Risk Drivers Addressed	Related Performance Metrics
the public before, during, and after major outages, PSPS events, and emergencies with information and resources needed to mitigate potential safety and economic impacts.			preparedness communications
8. Maintain a comprehensive, all-hazards planning and preparedness program to provide effective emergency response, safely and expeditiously restore service during and after a major event, and communicate effectively with customers, stakeholders, and agency partners.	DEP-2, DEP-5, Section 11.2	Reduces all wildfire and outage management risk drivers through procedures that standardize operations, such as precise application of PSPS criteria	Frequency of PSPS events, Scope of PSPS events, Duration of PSPS, Number of customers impacted by PSPS

3.3 Utility Mitigation Activity Tracking IDs

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

SCE uses numbered Tracking IDs throughout WMP tables and narratives to refer to activities within each initiative.

3.4 Prioritized List of Wildfire Risks and Risk Drivers

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

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

Table 3-1: List of Risks and Risk Drivers to Prioritize

Priority	**Risk**	**Risk Driver**	**x% of ignitions in HFTD[1]**	**Topographical and Climatological Risk Factors[2]**
1	Contact from object	Other contact from object	18.90%	Wind, temperature, water vapor, turbulence, kinetic energy,[3] humidity, rain and snow
2	Equipment / facility failure or damage	Transformer	12.50%	Wind, temperature, water vapor, turbulence, kinetic energy, humidity, rain and snow
3	Equipment / facility failure or damage	Insulator and bushing	11.90%	Wind, temperature, water vapor, turbulence, kinetic

1 Ignition data spans January 2019 to December 2024 and only considers FIPA (Fire Incident Preliminary Analysis) ignitions. N/A values indicate that the risk factor is not a category that we have used historically.

2 If listed, risk factors use the following climatological risk factors: wind, temperature, water vapor, turbulence kinetic energy, humidity, rain, and snow. The data is processed by aggregating 10 years of hourly data and calculating several statistical measurements for each climatological factor. These values are then set based on location.

3 Turbulence kinetic energy is a measure of the intensity of wind turbulence.

Priority	Risk	Risk Driver	x% of ignitions in HFTD[1]	Topographical and Climatological Risk Factors[2]
				energy, humidity, rain and snow
4	Equipment / facility failure or damage	Conductor	10.71%	Wind, temperature, water vapor, turbulence, kinetic energy, humidity, rain and snow
5	Contact from object	Animal contact	7.14%	Animal/aviation contact incidents, wind, temperature, water vapor, turbulence, kinetic energy, humidity, rain and snow
6	Equipment / facility failure or damage	Other	6.70%	Wind, temperature, water vapor, turbulence, kinetic energy, humidity, rain and snow
7	Vegetation contact	Fall-in (branch failure) Fall-in (trunk failure) Fall-in (root failure) Blow-in Grow-in	5.36%	Routine/hazard tree data, tree density/proximity, wind, temperature, water vapor, turbulence kinetic energy, humidity, rain and snow
8	Equipment / facility failure or damage	Connector device	4.32%	Wind, temperature, water vapor, turbulence, kinetic energy, humidity, rain and snow
9	Contact from object	Balloon contact	3.57%	Wind, temperature, water vapor, turbulence, kinetic energy, humidity, rain and snow
10	Contact from object	Land vehicle contact	3.42%	Fatal motor vehicle incidents, wind, temperature, water vapor, turbulence,

Priority	Risk	Risk Driver	x% of ignitions in HFTD[1]	Topographical and Climatological Risk Factors[2]
				kinetic energy, humidity, rain and snow
11	Equipment / facility failure or damage	Pole	2.98%	Wind, temperature, water vapor, turbulence, kinetic energy, humidity, rain and snow
12	Vandalism/ theft	Vandalism/ theft	1.93%	None. This risk driver is tracked by SCE but is not associated with any associated risk factors.
13	Equipment / facility failure or damage	Fuse	1.79%	Wind, temperature, water vapor, turbulence, kinetic energy, humidity, rain and snow
13	Unknown	Unknown	1.79%	Wind, temperature, water vapor, turbulence kinetic energy, humidity, rain, snow
14	Equipment / facility failure or damage	Capacitor bank	1.64%	Wind, temperature, water vapor, turbulence, kinetic energy, humidity, rain and snow
15	Equipment / facility failure or damage	Cross arm	1.19%	Wind, temperature, water vapor, turbulence, kinetic energy, humidity, rain and snow
15	Equipment / facility failure or damage	Switch	1.19%	Wind, temperature, water vapor, turbulence, kinetic energy, humidity, rain and snow
16	Equipment / facility failure or damage	Lightning arrestor	0.89%	Wind, temperature, water vapor, turbulence, kinetic energy, humidity, rain and snow

Priority	Risk	Risk Driver	x% of ignitions in HFTD[1]	Topographical and Climatological Risk Factors[2]
16	Other	All Other	0.89%	Wind, temperature, water vapor, turbulence kinetic energy, humidity, rain, snow
17	Wire-to-wire contact	Wire-to-wire contact	0.74%	Wind
18	Utility Work / Operation	Utility Work / Operation	0.45%	None. This risk driver is tracked by SCE but is not associated with any associated risk factors.
19	Equipment / facility failure or damage	Anchor/guy	0%	Wind, temperature, water vapor, turbulence, kinetic energy, humidity, rain and snow
19	Equipment / facility failure or damage	Recloser	0%	Wind, temperature, water vapor, turbulence, kinetic energy, humidity, rain and snow
19	Equipment / facility failure or damage	Sectionalizer	0%	Wind, temperature, water vapor, turbulence, kinetic energy, humidity, rain and snow
19	Equipment / facility failure or damage	Voltage regulator/booster	0%	Wind, temperature, water vapor, turbulence, kinetic energy, humidity, rain and snow
19	Contamination	Contamination	0%	Wind, temperature, water vapor, turbulence kinetic energy, humidity, rain, snow
19	Dig-in	Dig-in	0%	None. This risk driver is tracked by SCE but is not associated with any associated risk factors.
--	Contact from object	Aircraft vehicle contact	N/A	N/A

Priority	Risk	Risk Driver	x% of ignitions in HFTD[1]	Topographical and Climatological Risk Factors[2]
--	Contact from object	3rd party contact	N/A	N/A
--	Contact from object	Unknown	N/A	N/A
--	Equipment / facility failure or damage	Cutout	N/A	N/A
--	Equipment / facility failure or damage	Relay	N/A	N/A
--	Equipment / facility failure or damage	Splice	N/A	N/A
--	Equipment / facility failure or damage	Tap	N/A	N/A
--	Equipment / facility failure or damage	Tie wire	N/A	N/A
--	Equipment / facility failure or damage	Unknown	N/A	N/A
--	Protective device operation	Protective device operation	N/A	N/A
--	Lightning	Lightning	N/A	N/A

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

Table 3-1 indicates the historical frequency of each risk driver in SCE's HFRA. The values are developed based on SCE's Fire Incident Preliminary Analysis (FIPA) of ignitions from January 2019 to December 2024. SCE has fully populated the table based on its historical data and categorization of risk drivers. A risk driver with the % ignitions listed as "N/A" indicates that the risk factor is not a category that has been used historically.

The information that is presented in Table 3-1 is ranked for reporting purposes and does not reflect the approach SCE takes to reduce risk on its system. As explained in Chapters 5 and 6, SCE takes a portfolio approach to wildfire mitigation with the intention of selecting complementary activities that collectively reduce wildfire risk. SCE uses its Integrated Wildfire Mitigation Strategy (IWMS), which divides SCE's HFRA into three tiers of risk. As such, SCE does not force-rank individual risk drivers and then mitigate them in a linear sequence from "top to bottom."

The impact of an ignition depends on several factors, including location, topography, climate, and weather. As such, SCE has implemented its IWMS approach to prioritize activity deployment based on the potential for catastrophic wildfire consequences. This IWMS approach seeks to reduce the risk of catastrophic wildfires to the greatest extent possible. See Section 5.2.1.2 for a discussion of SCE's IWMS Risk Framework.

The topographical and climatological risk factors used for short-term and current risk modeling were determined via machine learning models. SCE has built a collection of asset-based risk models that target several of the risk factors listed above. The inputs to these models include the physical properties of the asset itself in addition to the risk factors listed. The risk factors are then analyzed to determine the impact of each risk factor on the corresponding risk driver. For a discussion of how these factors are considered in SCE's long-term risk modeling, please see Section 3.7.

3.5 Performance Metrics

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

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

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

Metrics listed in this section (including each metric's name and values) must match those reported in the applicable quarterly data submissions.

Table 3-2 provides an example of the minimum acceptable level of information and the required format.

SCE notes that performance metrics should have a clear distinction between the success of an electrical corporation in implementing its approved WMP versus the longer-term measurement of risk reduction. The WMP is a forward-looking plan, based on the premise that electrical corporations present a risk-informed approach that is evaluated and approved by Energy Safety. Compliance with the plan should be based on metrics that evaluate prudent implementation, such as completion of WMP program targets. Performance metrics that measure wildfire risk reduction should not be used to measure compliance with a WMP, as doing so effectively creates a hindsight standard.

Annual variations in external conditions such as fuel levels, moisture, and wind have dramatic effects on wildfire risk that make year-over-year comparisons challenging. Performance metrics that seek to understand overall wildfire risk reduction should consider at least a five-year time horizon and, even then, may be skewed by atypical years. For example, 2022 and 2023 featured unusually high levels of precipitation, which reduced the amount of dry vegetation fuel contributing to lower levels of wildfire risk. In contrast, 2024 was unusually dry and followed several years of unseasonable precipitation and vegetation growth which led to unprecedented levels of wildfire risk, as seen in extensive PSPS events throughout 2024 and the tragic fires in early 2025. It is difficult to isolate these annual variations from the impacts of mitigations that are implemented over the same time period.

SCE provides annual targets in the appropriate table of Chapters 8 through 12 for its WMP initiatives, which establish goals to evaluate SCE's compliance with its WMP. SCE has also provided the performance metrics that it uses to help evaluate the goal of reducing utility-related wildfire ignitions and the scope, duration, and frequency of PSPS. SCE will use these metrics, along with other data such as field observations and ignition investigations, to help inform its annual evaluation and consideration of potential changes for future Base WMPs or WMP Updates.

These metrics are feasible for utilities to influence through wildfire mitigation initiatives when appropriately normalized for weather and other exogenous factors. Other metrics such as safety incidents, acres burned or structures destroyed, though important to understand, track, and monitor, are impacted by events and circumstances largely outside of the utility's control such as climate change, droughts, fire suppression efforts and fire response.

Table 3-2: SCE Self-Identified Performance Metrics

Performance Metric	Assumption that underlies the use of the metric	Section associated with the Performance Metric (state "WMP" if the metric applies to entire plan)
1. Number of CPUC reportable ignitions in HFRA	Factors outside of SCE's control (e.g., wind, live fuel moisture) have a significant effect on CPUC reportable ignition counts in HFRA.	WMP
2. Number of wire downs in HFRA	Number of wire down incidents in HFRA based on cause. These metrics may help to provide insight on controllable and uncontrollable risks or help plan future activities to focus on a particular type of fault or outage that may pose a wildfire risk.	WMP
3. Number of outages in HFRA	Number of faults in HFRA based on cause. These metrics may help to provide insight on controllable and uncontrollable risks or help plan future activities to focus on a particular type of fault or outage that may pose a wildfire risk.	WMP
4. Number of asset management ignition risk-related work orders (excluding GO95 exceptions) that are past due	This metric will help track past due work orders that are related to wildfire risk mitigation and that are largely (excluding GO95 exceptions) within the utility's control.	8.6

Performance Metric	Assumption that underlies the use of the metric	Section associated with the Performance Metric (state "WMP" if the metric applies to entire plan)
5. Number of Tree-Caused Circuit Interruptions (TCCIs) in HFRA	Vegetation that comes into contact with energized circuits can cause a circuit interruption (e.g., fault), however there may be cases where vegetation comes into contact with SCE infrastructure and no fault occurs.	9
6. Number of trees inspected where at least some vegetation was found in a non-compliant condition in HFRA - Routine	Routine Line Clearing activities will identify instances in which vegetation exists in a non-compliant condition	9
7. Frequency of PSPS events (total)	Metric does not account for the normalization of weather, fuel conditions, etc., year over year.	WMP
8. Scope of PSPS events (total)	Metric does not account for the normalization of weather, fuel conditions, etc., year over year.	WMP
9. Duration of PSPS (total)	Metric does not account for the normalization of weather, fuel conditions, etc., year over year.	WMP
10. Number of customers impacted by PSPS	Metric does not account for the normalization of weather, fuel conditions, etc., year over year.	WMP
11a. % Customer recall of SCE wildfire and preparedness communications - System Wide	Results can be impacted by volume of PSPS events experienced per year, level of marketing and outreach to customers, severity of fire season, and other factors.	11

Performance Metric	Assumption that underlies the use of the metric	Section associated with the Performance Metric (state "WMP" if the metric applies to entire plan)
11b. % Customer recall of SCE wildfire and preparedness communications - HFRA only	Results can be impacted by volume of PSPS events experienced per year, level of marketing and outreach to customers, severity of fire season, and other factors.	11

3.6 Projected Expenditures

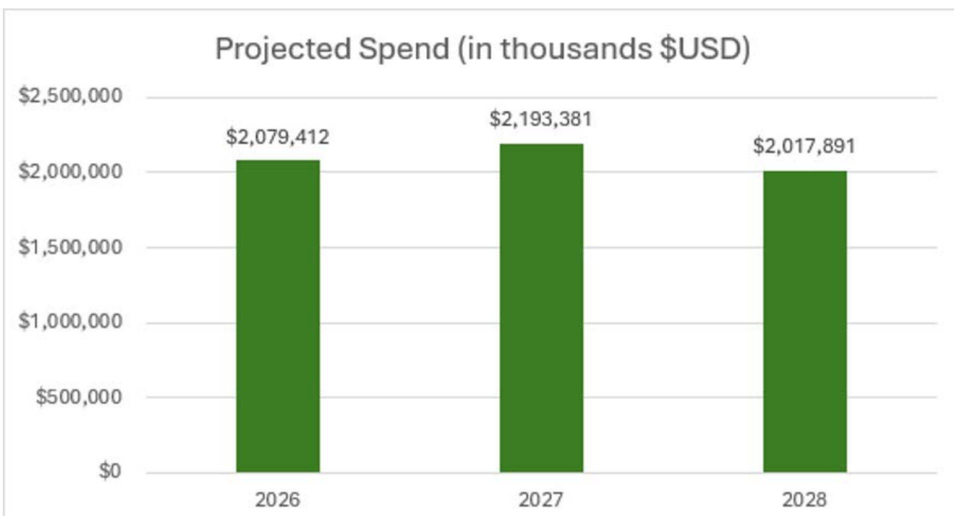
The electrical corporation must summarize its projected expenditures in thousands of U.S. dollars per year for the activities set forth in its three-year WMP cycle in both tabular and graph form. For tabular form, the electrical corporation must follow the provided format in Table 3-3.

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

Table 3-3: SCE Summary of Projected WMP Expenditures[4]

Year of WMP Cycle	**Spend (thousands $USD)**
2026	Projected = $2,079,412
2027	Projected = $2,193,381
2028	Projected = $2,017,891

Figure SCE 3-01: Graph of WMP Expenditures



3.7 Climate Change

In this section, the electrical corporation must describe how it has considered dynamic climate change risks in writing its WMP. This description must include reference to the

4 The summary of WMP Expenditures reflects direct capital and O&M costs for wildfire activities which correspond to the HFTD spend as shown in the QDR. The dollars are nominal.

electrical corporation's most recent climate vulnerability assessment addressing new or exacerbated risks related to wildfire. This section is limited to two pages.

SCE notes there are significant differences between the types of wildfire risk (utility-involved vs. utility-exposed) and the timeframes of analyses (short-term vs. long-term trend) used to support utility WMP, Risk Assessment Mitigation Phase (RAMP), and Climate Adaptation and Vulnerability Assessment (CAVA) filings. Utility CAVA filings are designed to evaluate "hazard" based exposure of utility assets, operations, and services to long-term changes in environmental conditions. This is different than utility wildfire ignition risk, which is an understanding of the probability of an ignition along with potential consequences.

Noting these differences, the Commission directed utilities to perform a pilot designed to integrate climate change into utility risk models in Phase III of the Risk-Informed Decision-Making Framework (RDF) proceeding. SCE is required to report the results of this Climate Change Pilot whitepaper no later than May 15, 2026, concurrent with its 2026 RAMP and CAVA filings. The purpose of the Climate Change Pilots is to understand how current and forecasted conditions may affect utility risk assessments. The pilots will also help determine how to best reflect the impacts of climate change on utility involved ignition risk within the short time frame required by utility RAMP filings. Conversely, utility CAVA filings are intended to understand utility exposure to wildfire risk over longer time periods (e.g., greater than ten years), which is well beyond the RAMP and/or WMP analytical window.[5] Therefore, while SCE intends to use the same underlying Global Climate Models (GCM) for both RDF Climate Change Pilots and CAVA, and may reach coincidental overlap in conclusions, each analysis has distinct intentions. For example, in 2025 SCE changed the scope of sub-transmission pole clearing based on CAVA analysis.[6]

Concurrently, the Commission issued guidance in the Climate Change Adaptation (CCA) Proceeding requiring utilities to use Shared Socioeconomic Pathway (SSP) 3-7.0 (a moderate to severe climate change scenario reaching approximately 7.0W/m2 radiative forcing by the year 2100)[7] as the reference scenario applicable to CAVA, RAMP, and General Rate Case (GRC) filings. Future SCE CAVA filings are required to utilize both 1.5° C and 2.0° C Global Warming Levels (GWLs). Under a SSP 3-7.0 reference scenario, GWLs of 1.5 and 2.0°C are projected to occur in the range of 2026-2038 and 2035-2058, respectively.[8]

Aligning with one of the reference scenarios used for CAVA, RAMP, and the GRC, SCE's Climate Change Pilot and SCE's FireSight 8 (Climate) scenario (see Section 5.3.2) reflect a

5 For additional information SCE's 2022 Climate Change Vulnerability Assessment (CAVA), see: https://www.sce.com/about-us/environment/climate-adaptation

6 For additional information on pole clearing, see Section 9.4.

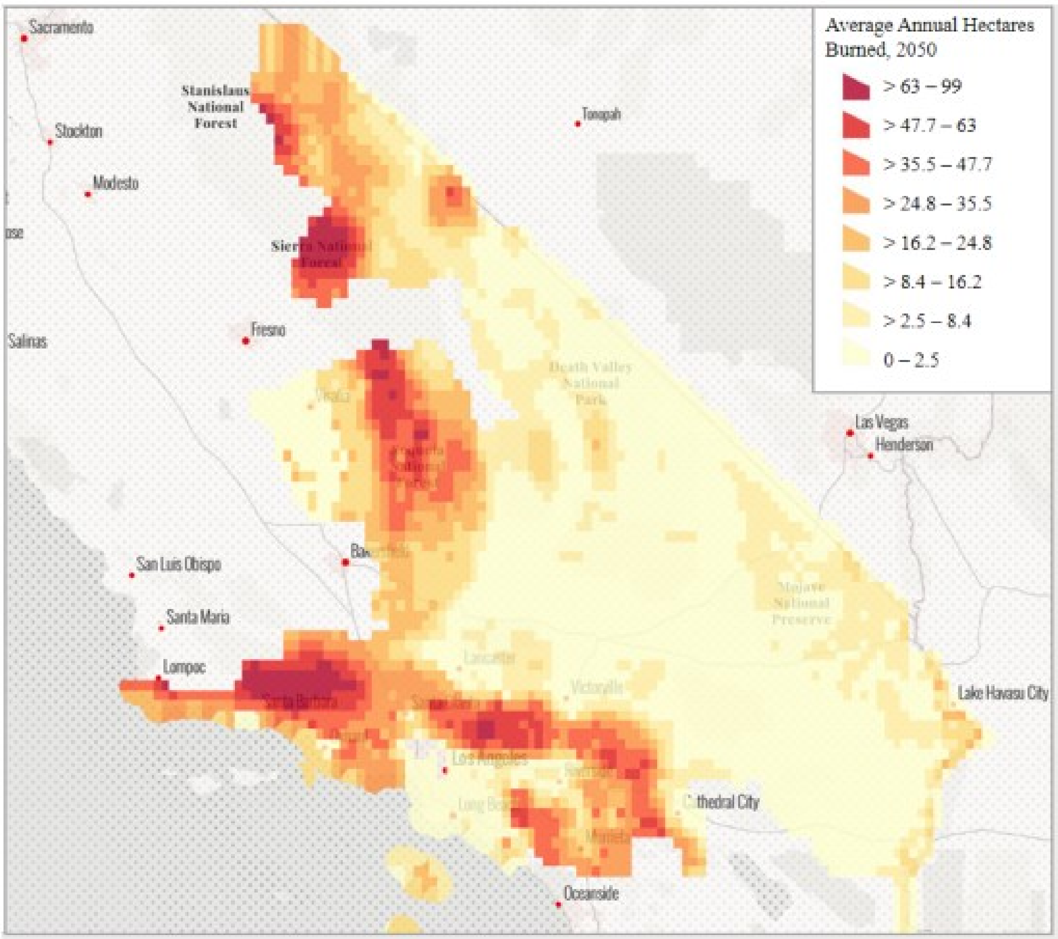
7 https://www.ipcc.ch/report/ar6/wg1/downloads/report/IPCC_AR6_WGI_FullReport.pdf

8 This guidance supersedes SCE's previous approach using Representative Concentration Pathway (RCP) used in SCE's previous Climate 2030 analysis.

2.0° C GWL between 2035 and 2058 under a SSP 3-7.0 reference scenario.[9] The timing of this analysis is critical as it allows us to inform mitigation activities with long effective useful lives (EUL) beyond SCE's next RAMP/GRC window. SCE's 2026 RAMP analysis covers infrastructure funding from 2029 through 2032.[10]

Average Annual Hectares Burned for 2050 using RCP 8.5 from SCE's 2022 CAVA, is depicted in Figure SCE 3-02.

Figure SCE 3-02: Illustration of Average Annual Hectares Burned, 2050



9 A preview of the methodology SCE intends to employ to simulate forward looking wildfire conditions (i.e., FireSight 8 [Climate]) can be found in Section 5.3.2 Extreme-Event/High Uncertainty Scenarios.

10 D. 24.05-064 Ordering Paragraph. 3d. "The IOUs should seek to avoid, if possible, any long-term asset investment strategy that would be at risk in the future because of climate change impacts."

In its 2025-2028 GRC, SCE proposed several climate adaptation investments across Generation, Sub-Transmission, and Distribution.[11] These proposals originated after SCE submitted its first CAVA in May 2022. Near-term proposals included expanded structure brushing on sub-transmission structures, investments in additional grid redundancy via circuit ties on distribution lines, and enhanced power and communications redundancy at hydroelectric facilities to support adaptation to wildfire climate change impacts. SCE also proposed several projects to address the risk of other climate change impacts such as flood, temperature increases, and cascading events such as debris flow.

11 Please see SCE's 2025 GRC Risk Policy, Climate Change Policy, and Environmental & Social Justice Goals Testimony, A.23-05-010, Ex. SCE-01, Vol. 02, pp. 32-42.

4 Overview of the Service Territory

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

4.1 Service Territory

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

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

Table 4-1 provides the required format for presenting the high-level service territory components.

The electrical corporation must also provide one geospatial representative map that shows its service territory (polygons) and the above required components. The electrical corporation must host this map and any geospatial layers on a publicly accessible web application as required by Chapter II.

Southern California Edison (SCE) is one of the nation's largest electric utilities. It serves approximately 15 million people across 180 cities and 15 counties.[12] SCE provides high-level statistics for its service territory and electrical equipment in Table 4-1, below.

12 Data as of 1/29/2025. See https://www.sce.com/about-us

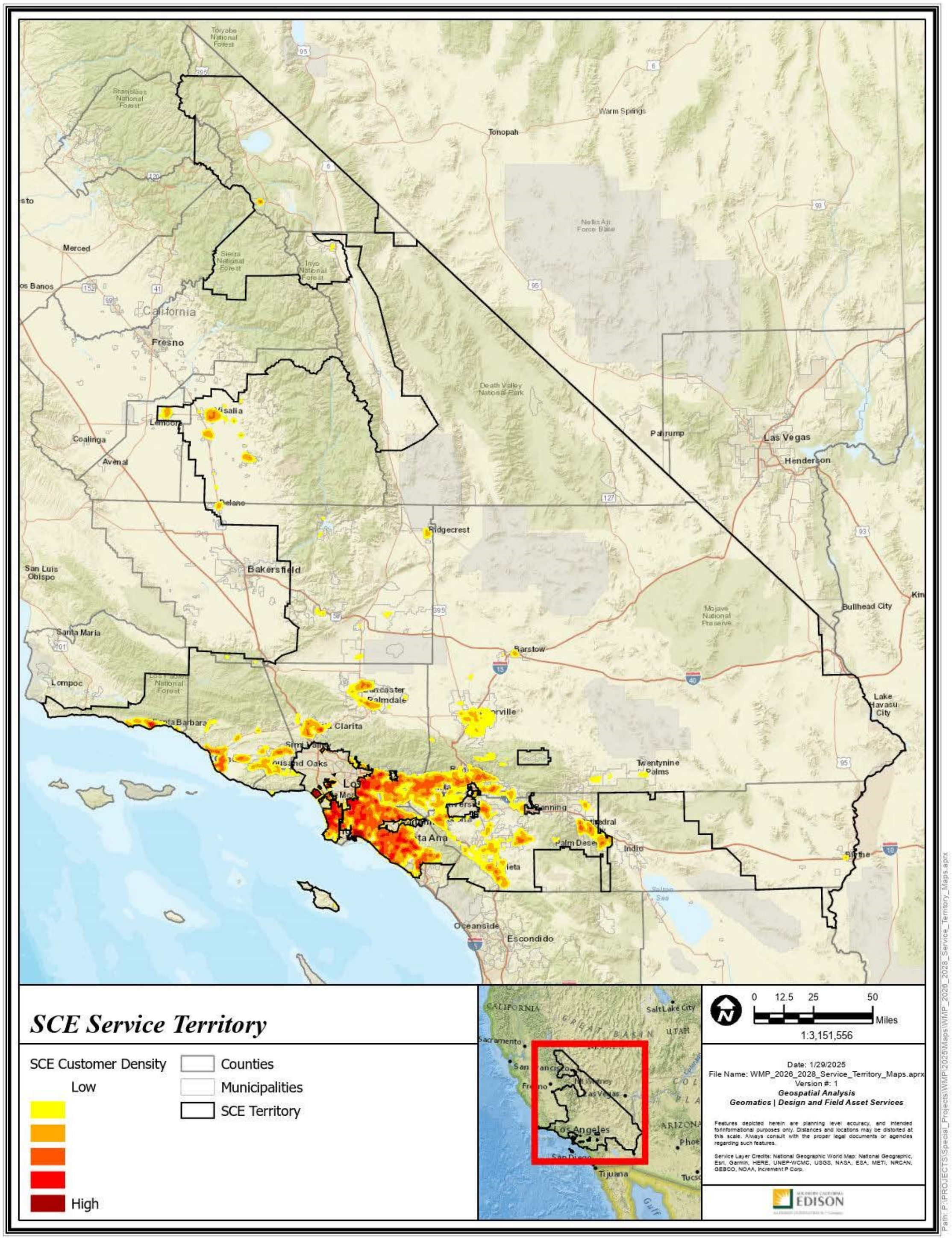
Table 4-1: SCE High-Level Service Territory Components13

Characteristic	HFTD Tier 2	HFTD Tier 3	Non-HFTD	Total
Area served (sq. mi.)	9,608	4,707	37,942	52,256
Number of customers served (accounts)	284,615	462,909	4,521,285	5,268,809
Overhead transmission lines (circuit miles)	1,988	2,429	8,318	12,735
Overhead distribution lines (circuit miles)	3,820	5,522	28,476	37,818
Underground transmission lines (circuit miles)	21	45	306	372
Underground distribution lines (circuit miles)	3,029	4,318	24,265	31,612

Figure SCE 4-01 shows SCE's distribution of customers served by meter density while Figure SCE 4-02 shows transmission and distribution lines, within SCE's service territory, county, and city administrative boundaries.

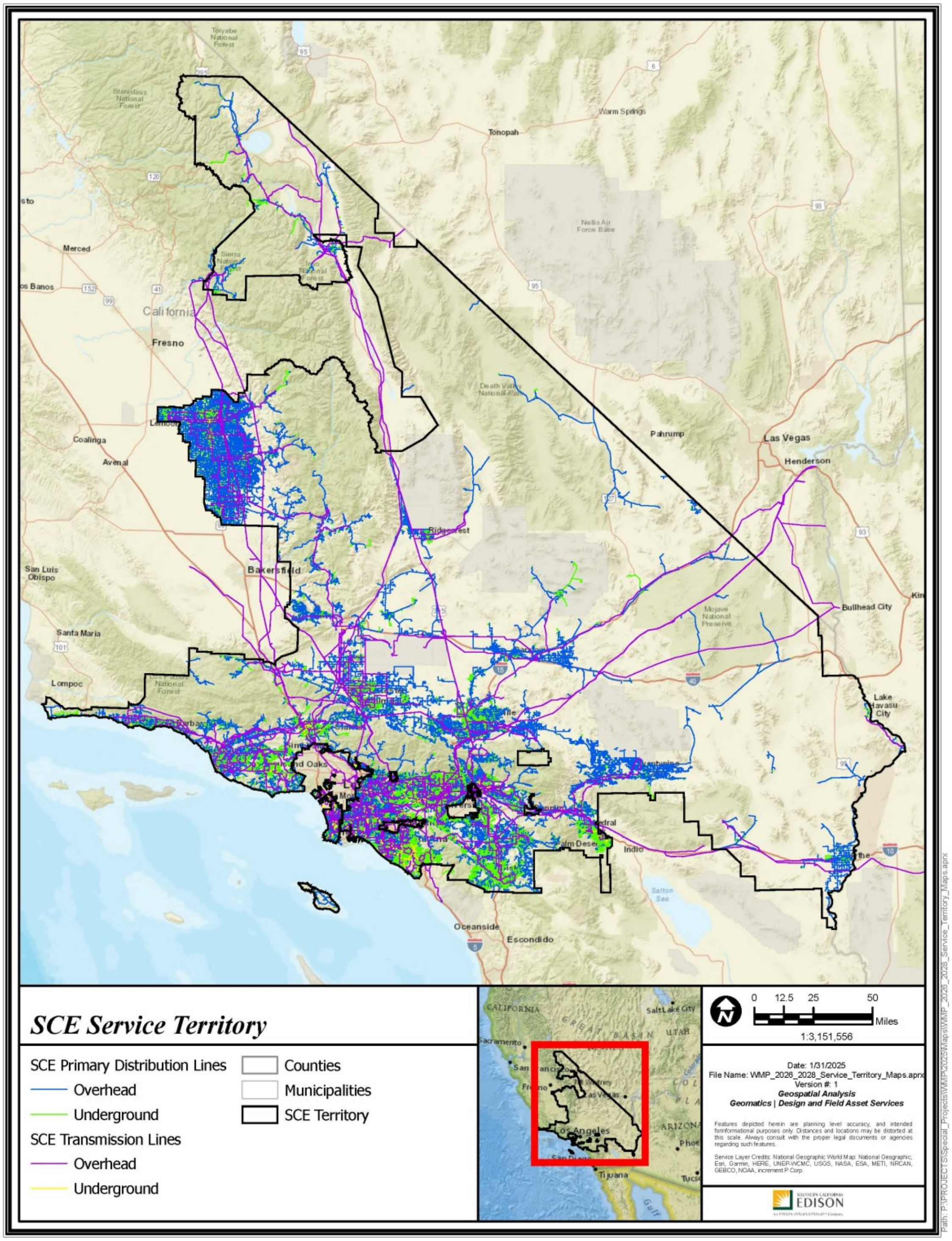
13 Data as of 1/29/2025.

Figure SCE 4-01: SCE Service Territory and Customer Meter Density Map14



14 Map as of 1/29/2025. SCE has provided spatial data for SCE's service territory. Please see https://www.sce.com/wmp. The California Public Utilities Commission High Fire Threat District Map is available publicly at: https://capuc.maps.arcgis.com/apps/webappviewer/index.html?id=5bdb921d747a46929d9f00dbdb6d0fa2.

Figure SCE 4-02: SCE Service Territory and Electrical Infrastructure Map5



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15 Map as of 1/29/2025. SCE has provided spatial data for SCE's service territory. Please see https://www.sce.com/wmp. The California Public Utilities Commission High Fire Threat District Map is available publicly at: https://capuc.maps.arcgis.com/apps/webappviewer/index.html?id=5bdb921d747a46929d9f00dbdb6d0fa2.

4.2 Catastrophic Wildfire History

The electrical corporation must provide a brief narrative summarizing its wildfire history for the past 20 years as recorded by the electrical corporation, CAL FIRE, or other authoritative government sources. For this section, wildfire history must be limited to electrical corporation ignited catastrophic fires[16] (i.e., fires that caused at least one death, damaged over 500 structures, or burned over 5,000 acres). This includes catastrophic wildfire ignitions reported to the CPUC that may be attributable to facilities or equipment owned by the electrical corporation and where the cause of the ignition is still under investigation by the CPUC, CAL FIRE, and/or other authoritative government sources. The electrical corporation must clearly denote those ignitions as still under investigation. In addition, the electrical corporation must provide catastrophic wildfire statistics in the tabular form provided below, including the following key metrics:

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

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

SCE provides the requested information in Table 4-2 below. SCE has listed wildfires that meet the definition of "catastrophic" as provided by Energy Safety in the WMP Guidelines shown above. Table 4-2 includes fires where an investigating agency opined that SCE utility infrastructure was the likely cause of an ignition, or where SCE reported to the CPUC that the fire potentially involved utility infrastructure but where the cause of the fire is still under investigation. Because SCE is providing information in accordance with the definitions and templates required by Energy Safety, the information provided below should not be construed as an admission of any wrongdoing or liability by SCE. SCE does not guarantee the damage metrics provided by other agencies. In many instances the cause of wildfires are still under investigation, and even where an Authority Having Jurisdiction (AHJ) has issued a report on the cause(s), unless otherwise stated, SCE may dispute the conclusions of such report.

[16] Definition provided by OEIS WMP guidelines.

Table 4-2: Catastrophic Wildfires

Ignition Date[17]	Fire Name	Official Cause[18]	Fire Size (acres)	No. of Fatalities	No. of Structures Destroyed and Damaged	Financial Loss (US$)[19]	Lesson(s) Learned
10/20/2007	RANCH	USFS opined that the fire was caused by SCE equipment	>58,000	0	9 Structures Damaged or Destroyed	Data not available	See Section 4.2 narrative
11/14/2008	SAYRE	USFS opined that the fire was caused by SCE equipment	11,262	0	604 Structures Destroyed / 147 Structures Damaged	Data not available	See Section 4.2 narrative
2/6/205	ROUND	CAL FIRE opined that the fire was caused by SCE equipment	7,000	0	43 Structures Destroyed / 5 Structures Damaged	Data not available	See Section 4.2 narrative
8/18/2016	REY	USFS opined that the fire was caused by SCE equipment	32,606	0	5 Structures Destroyed	Data not available	See Section 4.2 narrative
12/4/2017	THOMAS/ KOENIGSTEIN	CAL FIRE & VCFD opined that the fires were caused by SCE equipment	281,893	2	1,060 Structures Destroyed / 274 Structures Damaged	Data not available	See Section 4.2 narrative

17 Wildfire history data is derived from various sources including SCE incident reports and related communications, CAL FIRE (https://www.fire.ca.gov/stats-events/), and U.S Forest Service (https://nap.nwcg.gov/NAP/).

18 Wildfire history data is derived from various sources including SCE incident reports and related communications, CAL FIRE (https://www.fire.ca.gov/stats-events/), and U.S Forest Service (https://nap.nwcg.gov/NAP/).

19 In some instances, an agency may provide data related to one component of financial loss such as costs associated with suppression efforts; however, SCE is not aware of an authoritative government source that provides all-inclusive data regarding financial loss.

Ignition Date[17]	Fire Name	Official Cause[18]	Fire Size (acres)	No. of Fatalities	No. of Structures Destroyed and Damaged	Financial Loss (US$)[19]	Lesson(s) Learned
12/5/2017	CREEK	USFS opined that fire was caused by LADWP equipment	15,619	0	123 Structures Destroyed / 81 Structures Damaged	Data not available	See Section 4.2 narrative
12/5/2017	RYE	CAL FIRE opined that the fire was caused by SCE equipment	6,049	0	6 Structures Destroyed / 3 Structures Damaged	Data not available	See Section 4.2 narrative
11/8/2018	WOOLSEY	CAL FIRE opined that the fire was caused by SCE equipment and an unidentified communication line	96,949	3	1,643 Structures Destroyed / 364 Structures Damaged	Data not available	See Section 4.2 narrative
10/10/2019	SADDLE RIDGE	Los Angeles City Fire Dept opined that the cause of the fire is undetermined	8,799	1	24 Structures Destroyed / 91 Structures Damaged	Data not available	See Section 4.2 narrative
9/6/2020	BOBCAT	USFS opined that the fire was caused by SCE equipment	115,997	0	169 Structures Destroyed / 47 Structures Damaged	Data not available	See Section 4.2 narrative
10/26/2020	SILVERADO	CAL FIRE and OCFA opined that the fire was caused by SCE and T-Mobile equipment	12,466	0	5 Structures Destroyed / 11 Structures Damaged	Data not available	See Section 4.2 narrative

Ignition Date[17]	Fire Name	Official Cause[18]	Fire Size (acres)	No. of Fatalities	No. of Structures Destroyed and Damaged	Financial Loss (US$)[19]	Lesson(s) Learned
9/5/2022	FAIRVIEW	CAL FIRE opined that the fire was caused by SCE equipment	28,307	2	36 Structures Destroyed / 8 Structures Damaged	Data not available	See Section 4.2 narrative
1/7/2025	EATON	No official cause. Under investigation	14,021	17	9,413 Structures Destroyed / 1,074 Structures Damaged	Data not available	See Section 4.2 narrative

SCE identifies the following wildfires that meet Energy Safety's definition of "catastrophic" over the past 20 years wherein SCE, CAL FIRE, or another authoritative source opined that the fire was likely ignited by electrical equipment, or where the cause(s) of the fire is still under investigation. The information provided below should not be construed as an admission of any wrongdoing or liability by SCE.

i. The Ranch Fire ignited on 10/20/2007 wherein the United States Department of Agriculture (USDA) United States Forest Service (USFS) opined that during extreme Santa Ana Wind conditions, a preform attached to a bell-type insulator on a distribution circuit broke, causing the insulator to pull away from the steel tower and suspending it while still attached to the tap line. The winds caused the conductor to swing back and forth allowing the bell insulator to make contact with a section of the tower and ignited the fire.
ii. The Sayre Fire ignited on 11/14/2008 wherein the USDA (USFS) opined that phase-to-phase conductor contact during windy conditions ignited the fire.
iii. The Round Fire ignited on 2/6/2015 wherein CAL FIRE opined that a decayed tree fell into an overhead line and ignited the fire.
iv. The Rey Fire ignited on 8/18/2016 wherein the USDA (USFS) opined that a large portion of an oak tree split and landed on underbuilt communication lines, which pulled down the poles causing an electric line to separate and ignited the fire.
v. The Thomas Fire/Koenigstein Fire ignited on 12/4/2017 wherein CAL FIRE and Ventura County Fire Department opined that the Thomas Fire ignited from phase-to-phase conductor contact in a wind event and the Koenigstein Fire ignited from downed energized conductor during the same wind event.
vi. The Rye Fire ignited on 12/5/2017 wherein CAL FIRE opined that a strand-vise device that connected a transmission down-guy to the guy anchor failed, causing the guy wire to whip through the air and make contact with a jumper on an underbuilt distribution circuit and ignited the fire.
vii. The Creek Fire ignited on 12/5/2017 wherein the USDA (USFS) initially opined that powerlines on an LADWP-owned transmission circuit ignited the fire but recently changed its opinion and issued a report implicating SCE's facilities.
viii. The Woolsey Fire ignited on 11/8/2018. A slack transmission down-guy made contact in high winds with a jumper on an underbuilt distribution circuit energizing distribution guy wires and energizing SCE and unidentified communications lines resulting in two ignition sites.
ix. The Saddle Ridge Fire ignited on 10/10/2019 wherein Los Angeles City Fire Department opined that the cause of the fire was undetermined.
x. The Bobcat Fire ignited on 9/6/2020 wherein the USFS opined that the fire was caused by contact of a tree limb with powerlines operated and maintained by SCE.
xi. The Silverado Fire ignited on 10/26/2020 wherein CAL FIRE and OCFA opined that the fire was caused by an unspecified electrical event between SCE and T-Mobile lines.
xii. The Fairview Fire ignited on 9/5/2022 wherein CAL FIRE opined that a sagging overhead electrical distribution line owned and operated by SCE contacted a Frontier communication line and caused an electrical arch, igniting the fire.
xiii. The Eaton Fire ignited on 1/7/2025, and the cause(s) of the fire is still under investigation by SCE, the Los Angeles County Fire Department, and CAL FIRE.

SCE has a formal process to investigate ignitions (catastrophic and non-catastrophic). This can lead to changes to SCE's inspection practices, vegetation management practices, modifications to SCE's engineering standards, or the introduction of new mitigation strategies. Section 8.4 provides further detail on SCE's Fire Incident Preliminary Analysis (FIPA) process to investigate ignitions and derive lessons learned.

Several wildfires are still under investigation. There are some for which SCE filed an Electrical Safety Incident Report in an abundance of caution, even though SCE affirmatively disputes that its equipment was associated with each ignition based on current information.

SCE consistently evaluates opportunities to incorporate any lessons learned into its construction and maintenance practices or future mitigation strategies. Separately, SCE is in the process of implementing system enhancements to strengthen SCE's electric system, support community engagement activities, and make investments in safety studies, pursuant to an agreement between SCE and the CPUC's Safety Enforcement Division, as adopted by the CPUC in Resolution SED-5 and SED-5A.[20] Further information can be found through the CPUC's website.[21]

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20 Resolution SED-5 Approving Administrative Consent Order and Agreement of the Safety and Enforcement Division and Southern California Edison Company (U338-E) Regarding the 2017/2018 Southern California Fires Pursuant to Resolution M-4846. December 16th, 2021.

21 *See* https://www.cpuc.ca.gov/regulatory-services/enforcement-and-citations.

4.3 Frequently Deenergized Circuits

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

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

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

The map must show the following:

- *All circuits listed in Table 4-3, colored or weighted by frequency of PSPS*
- *HFTD Tiers 2 and 3 contour overlay*

Examples of the minimum acceptable level of information and the required format are provided in Table 4-3. If this table is longer than two pages, once populated, the electrical corporation must append the table as an appendix to the WMP.

SCE provides the tabulated data from 2019 to 2024 for Table 4-3 in F1 – Continuation of Section 4.3 Frequently Deenergized Circuits Appendix F due to the size of the table. This section requests electrical corporations to provide projections for future deenergizations and customer impacts. PSPS events are a function of future weather conditions and cannot be predicted with a meaningful level of certainty. Between 2023 and 2025, SCE's service territory saw more extreme fire weather with each subsequent year, prompting an annual increase in PSPS. If in future years current trends of extreme weather and fire conditions continue, PSPS events will continue and may increase in frequency and duration as an essential mitigation of last resort to protect public safety.

Table 4-3: Frequently Deenergized Circuits[22]

Entry #	Circuit ID[23]	Name of Circuit	Dates of Outages[24]	Number of Customers Hours of PSPS per Outage[25]	Measures Taken, or Planned to Be Taken, to Reduce the Need for and Impact of Future PSPS of Circuit[26]	Estimated Annual Decline in PSPS Events and PSPS Impact on Customers
SCE provides the tabulated data for Frequently Deenergized Circuits in Appendix F: Supplemental Information.						

22 Data may be found at https://www.sce.com/wmp.

23 Pursuant to the guidance, SCE has only included circuits that experienced three or more deenergizations in a year for the 6 years prior to the submission of this WMP. Such circuits are not included in years in which they only experienced two or fewer deenergizations.

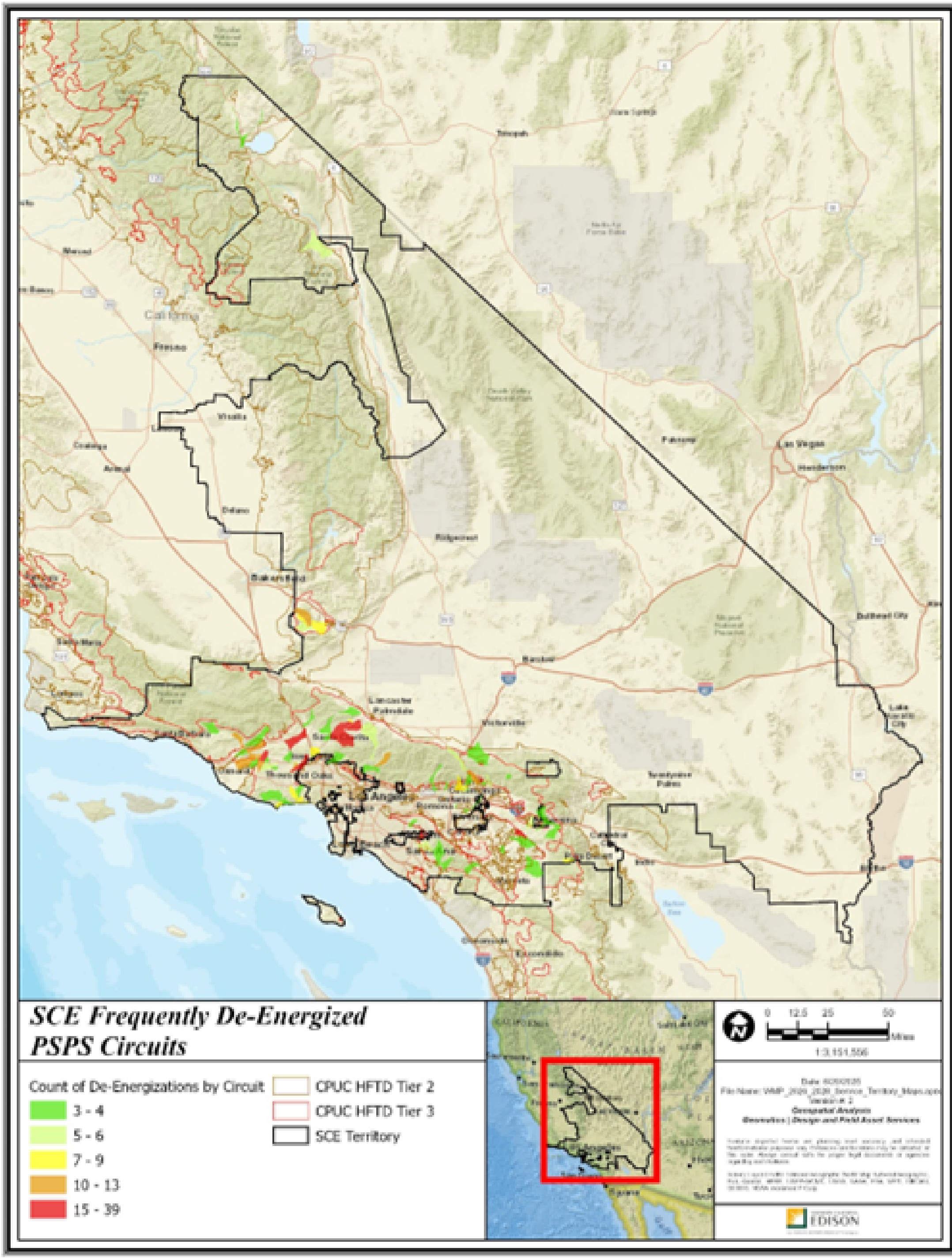
24 For Date of Outage, SCE provides the event de-energization date.For the dates listed, multiple deenergizations may have occured on the same date.

25 For Customer Hours of PSPS per Outage per Circuit, SCE calculates by isolation device or segments the difference between reenergization time and deenergization time in hours multiplied by the total customers impacted, summed for each circuit. PSPS tracking and reporting varied until 2021. As such, SCE was not able to produce comparable values of customer hours of PSPS per outage per circuit for 2019, 2020, or 2021.

26 SCE lists here measures taken or planned to reduce PSPS impacts. This might not include all wildfire mitigations on a circuit, as some measures are taken or planned to reduce wildfire risk. For example, there may be more covered conductor, REFCL, or other system hardening performed on each circuit than listed in this table.

Figure SCE 4-03 shows a map of the frequently de-energized circuits. SCE has provided spatial data for the frequently de-energized circuits, which can be found on SCE's website.[27]

Figure SCE 4-03: SCE Frequently De-Energized Circuits[28]



27 Please see https://www.sce.com/wmp.

28 Map data as of 6/2/2025. SCE has provided spatial data for SCE's service territory at https://www.sce.com/wmp.

5 RISK METHODOLOGY AND ASSESSMENT

In this section of the 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 section must provide the information necessary to understand the foundation for the electrical corporation's wildfire mitigation strategy. Sections 5.1-5.7 below provide detailed instructions.

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

5.1 Methodology

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

5.1.1 Overview

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

SCE uses its Multi Attribute Risk Score (MARS) methodology to quantify overall utility, wildfire risk, and outage program risk within SCE's High Fire Risk Areas (HFRA).[29] The resulting risk scores are used to inform the selection and prioritization of wildfire mitigation activities.

The MARS methodology converts Wildfire risk (wildfire likelihood and wildfire natural unit consequence) and Outage Program risk (consisting of PSPS risk [PSPS Likelihood and PSPS natural unit consequences] and PEDS risk [PEDS Likelihood and PEDS natural unit consequences]) into a unitless risk score. These resulting unitless wildfire and outage program risk scores are summed to provide overall utility risk scores and used in conjunction with mitigation effectiveness and mitigation cost information to inform the selection and prioritization of mitigation activities.

In addition to the quantitative information provided by the MARS methodology, SCE also uses its Integrated Wildfire Mitigation Strategy (IWMS) Framework to segment risk based on specific location-based risk factors, which are not fully captured by the MARS methodology. These additional factors include fire risk egress constraints, high wind locations which exceed covered

29 Multi-attribute Risk Score (MARS) is SCE's version of the Multi-attribute Value Function (MAVF) required to calculate risk under the 2018 S-MAP settlement, as amended by Phase I-III of the Risk Informed Decision-Making Proceeding R.20-07-013.

conductor wind thresholds, as well as Communities of Elevated Fire Concern (CEFC). SCE's approach is consistent with industry best practice and has been extensively discussed in the OEIS-led risk working group as well as the Rulemaking to Further Develop a Risk-Based Decision-Making Framework[30] at the Commission.

The IWMS Risk Framework segments risk in SCE's HFRA into three categories: Severe Risk Area (SRA), High Consequence Areas (HCA) and Other Areas (Other). Given that this framework is primarily used to augment the MARS methodology, which already factors in both consequence and probability, the IWMS Risk Framework does not include any additional adjustments for probability of ignition.[31] SCE uses this approach because the probability of ignition changes over time due to many variables, such as age, loading, etc. Additionally, in some locations the consequences of an ignition may be so extreme that it is prudent to mitigate ignition risk regardless of existing probability. Furthermore, climate change will exacerbate existing conditions (see Section 3.7 for additional detail).

The IWMS Risk Framework supports SCE's strategy to deploy mitigations commensurate with the level of consequence from a safety, financial, and reliability perspective within each location of its HFRA. After mitigations have been evaluated using the MARS methodology, SCE uses this preferred list of mitigations in combination with the IWMS Risk Framework risk segmentation as a key input to determine the location, scale, scope, and frequency for those mitigations.

In Section 5.2.1, SCE provides diagrams to illustrate how each framework uses the individual risk components defined by the WMP guidelines. Each diagram should be considered as unique to its respective framework.

5.2 Risk Analysis Framework

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

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

- ***Equipment / Assets** (e.g., type, age, inspection, maintenance procedures, etc.)*
- ***Topography** (e.g., elevation, slope, aspect, etc.)*
- ***Weather** (at a minimum this must include statistically extreme conditions based on weather history and seasonal weather)*
- ***Vegetation** (e.g., type/class/species/fuel model, canopy height/base height/cover, growth rates, moisture content, inspection, clearance procedures, etc.)*

30 R.20-07-013.

31 Probability of ignition (POI) is both the probability an ignition involving utility assets may occur (i.e., ignition likelihood), as well as the fraction those ignition events may transition to wildfire events (i.e., wildfire likelihood). See Section 5.2.2.1 for more details.

- ***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 populations (AFN), socioeconomic factors, etc.)*
- ***Physical vulnerability*** *(e.g., people, structures, critical facilities/infrastructure, etc.)*
- ***Access capacities*** *(e.g., limited access/egress, etc.)*

SCE provides its key modeling assumptions in Section 5.2.3. The factors listed above (e.g., Equipment/Assets, Topography, etc.) are summarized below in Table SCE 5-01.

Table SCE 5-01: Risk Quantification Factors

Factors	MARS Framework[32]	IWMS Risk Framework[33]
Equipment/Assets	Included in Wildfire POI component	Evaluated during the Review & Revise stage of the IWMS Risk Framework
Topography	Included in Wildfire Consequence Component	Included in Wildfire Consequence Component and in IWMS Risk Framework[34]
Weather	Included in POI and Wildfire Consequence Components	Included in Wildfire Consequence Component and in IWMS Risk Framework
Vegetation	Included in POI and Wildfire Consequence Components	Included in Wildfire Consequence Component and in IWMS Risk Framework
Climate change	Not currently factored [35]	Not currently factored
Social vulnerability	Included in Wildfire and PSPS Consequence Components	Not directly factored
Physical vulnerability	Included in Wildfire and PSPS Consequence Components	Included in IWMS Risk Framework
Access Capacities	Not directly factored	Included in IWMS Risk Framework

32 The MARS Framework was initially described in Section 5.1.1 and is further described in Section 5.2.1.1.

33 The IWMS Risk Framework was initially described in Section 5.1.1 and is further described in Section 5.2.1.2

34 See Section 5.2.1 for additional details.

35 See Section 3.7 for additional details regarding ongoing work to develop forward looking climate change scenarios.

5.2.1 Risk and Risk Component Identification

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

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

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

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

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

There are a minimum of nine intermediate risk components:

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

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

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

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

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

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

- ***PEDS outage risk:** The total expected annualized impacts from outages when PEDS was enabled at a specific location.*

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

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

There are a minimum of eleven fundamental risk components:

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

- ***Contact from vegetation ignition likelihood:** The likelihood that vegetation will contact electrical corporation-owned equipment and result in an ignition.*

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

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

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

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

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

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

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

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

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

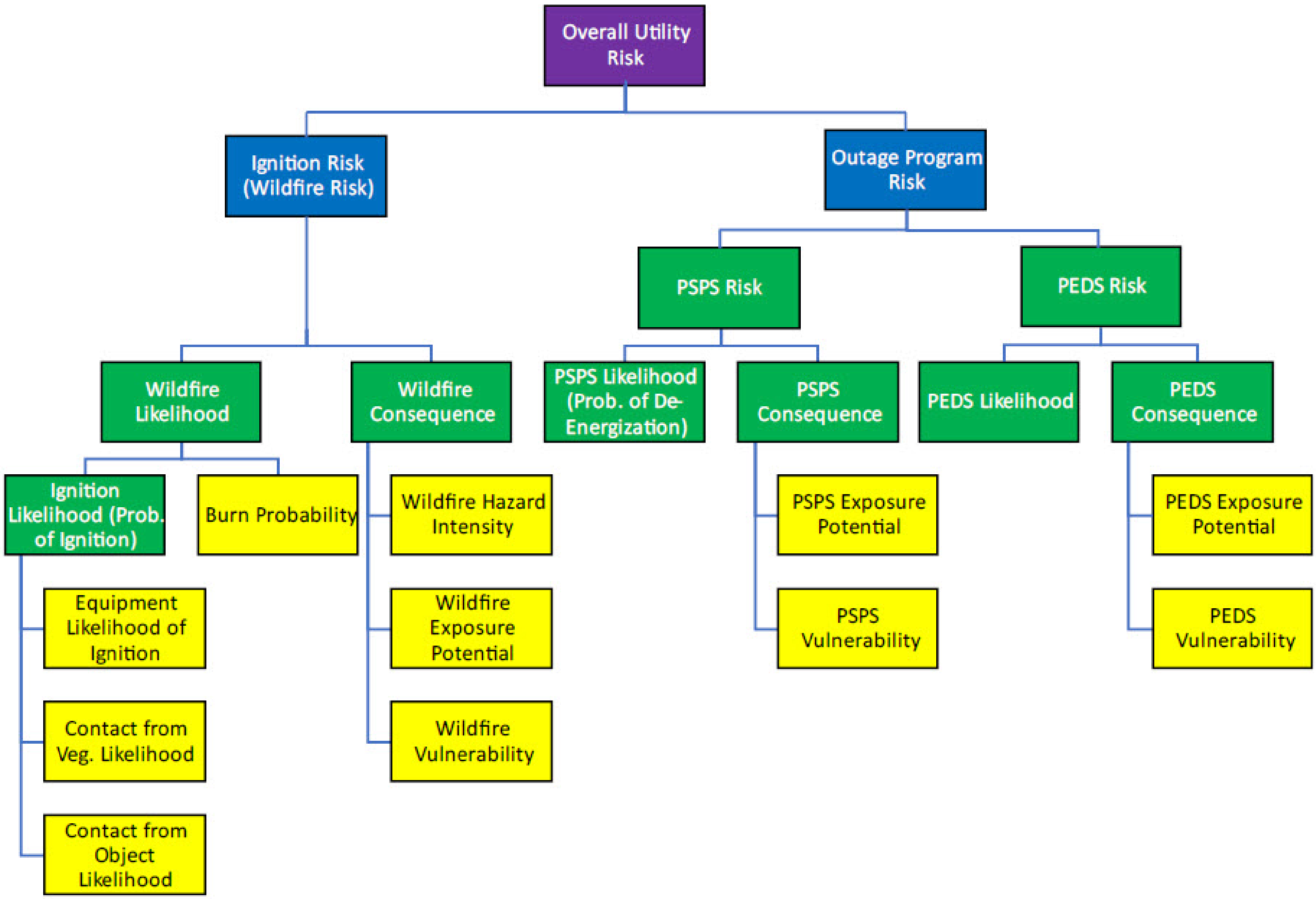
The electrical corporation must adopt these definitions for this section of the WMP. If the electrical corporation considers additional intermediate and fundamental risk components, it must define those components in this section as well.

5.2.1.1 MARS Framework

Multi-attribute Risk Score (MARS) is SCE's version of the Multi-attribute Value Function (MAVF) required to calculate risk under the 2018 S-MAP settlement, as amended by Phase I-III of the Risk Informed Decision-Making Proceeding R.20-07-013.

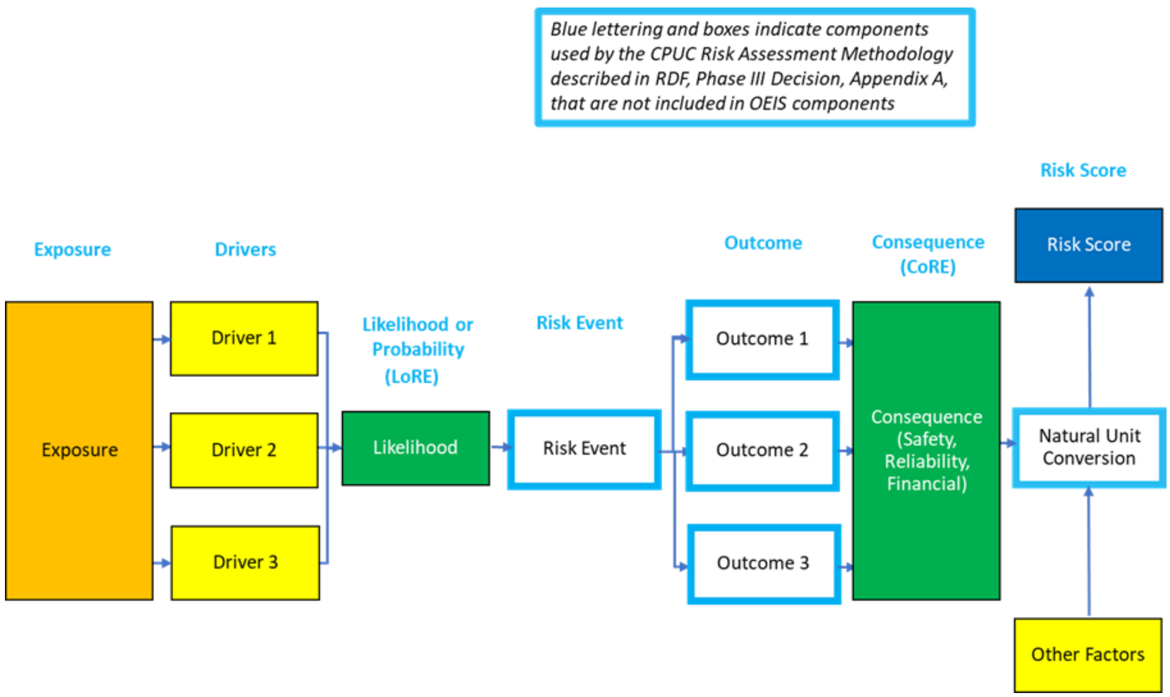
The diagram below depicts how SCE uses the OEIS prescribed risk components. The colors match how Energy Safety has presented the risk components in Figure 5-1.

Figure 5-1: SCE Composition of Overall Utility Risk Using OEIS Prescribed Risk Comps



The figure below depicts how SCE uses the CPUC prescribed risk components. The colors match how Energy Safety has presented risk components in Figure 5-1. Additional detail is provided in Section 5.2 and where applicable.

Figure SCE 5-01: Illustrative Risk Bowtie Consistent with CPUC Risk Informed Decision-Making Framework (RDF)[36]



To quantify risk scores for individual risks (e.g., wildfire, outage program), SCE leverages the RDF Risk Bowtie tool along with its MARS methodology to quantify overall utility, wildfire risk, and outage program risk within SCE's HFRA.[37] The resulting risk scores are used to inform the selection and prioritization of wildfire, PSPS, and PEDS mitigation activities. See Section 5.2 for a description of the methodology used to calculate risk scores.

The following definitions describe various components of the risk bowtie tool, based on the definitions (from left to right in the above schematic) used in the latest CPUC RDF Proceeding, Phase III Decision.[38] SCE additionally describes how its methodology for modeling and quantifying wildfire risk is consistent with the CPUC methodology in Section 5.2.

- ***Risk*** refers to the potential for the occurrence of an event that would be desirable to avoid, often expressed in terms of a combination of various Outcomes of an adverse event and their associated Probabilities. Note: SCE considers wildfire, PSPS, and PEDS as individual risks.
- ***Risk Score*** is a numerical representation of the risk to relatively rank and prioritize. Note: SCE uses risk scores to convey the sum of natural unit consequences for the purpose of

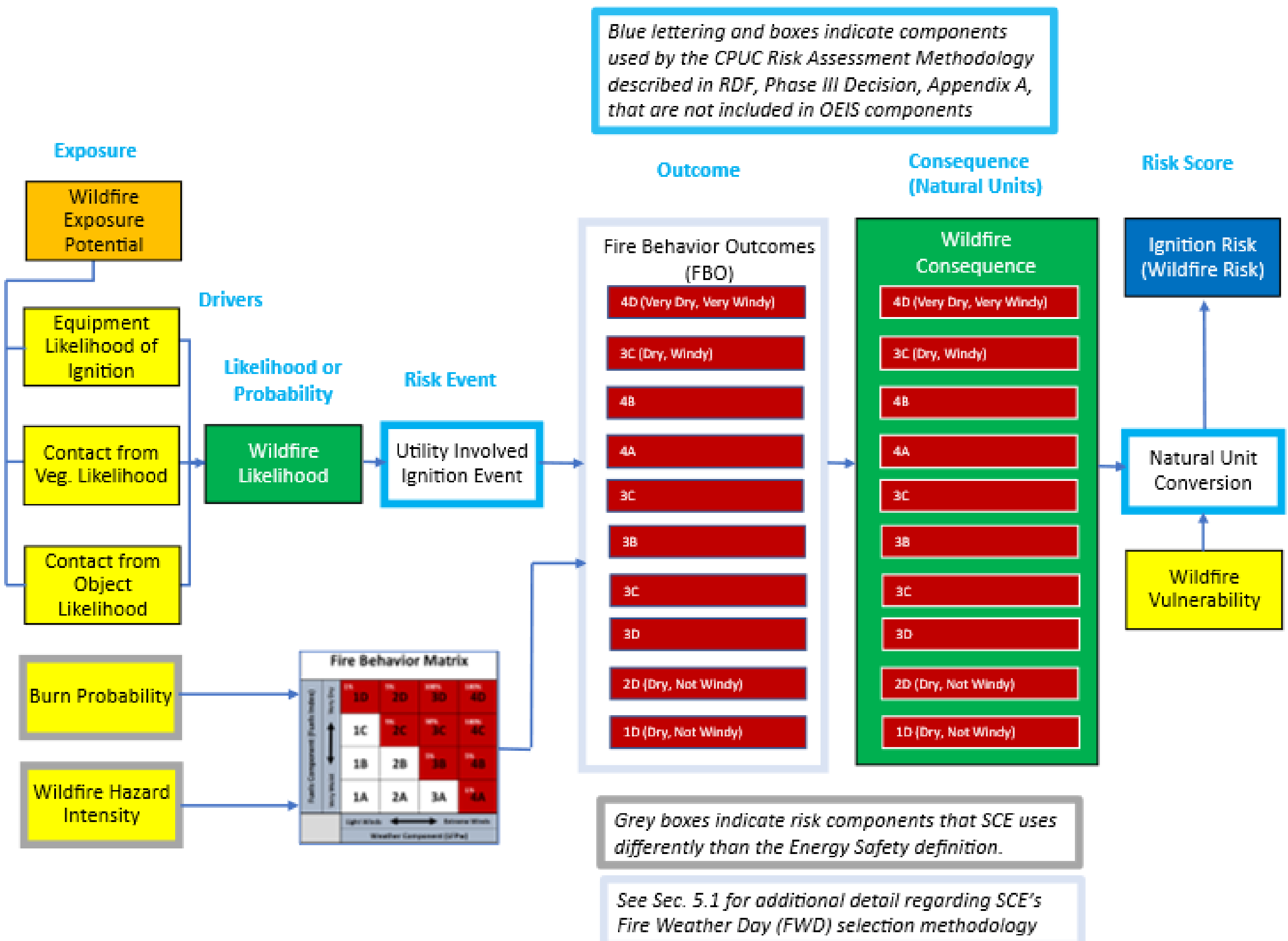
36 CPUC Risk Informed Decision-Making Proceeding R.20-07-013.
37 Per MAVF requirements for calculating risk under the 2018 S-MAP settlement, as amended by Phase I-III of the Risk Informed Decision-Making Proceeding, R.20-07-013.
38 CPUC Risk Informed Decision-Making Proceeding R.20-07-013.

developing assessments of cost effectiveness, and for prioritizing the deployment of mitigation activities. See Section 5.2 for a description of the methodology used to calculate risk scores.

- ***Bowtie*** is a tool that consists of the *Risk Event* in the center, a listing of *Drivers* on the left side that potentially lead to the *Risk Event* occurring, and a listing of *Consequences* on the right side that show the potential *Outcomes* if the *Risk Event* occurs. Note: SCE has individual bowties for each – Wildfire, PSPS, and PEDS – risks. See Appendix B for additional detail. SCE also provides an illustrative risk bowtie for wildfire risk in Section 5.2 in the context of its FireSight 8 methodology.
- ***Exposure*** is the measure that indicates the scope of the *Risk*, e.g., miles of transmission pipeline, number of employees, miles of overhead distribution lines, etc. Exposure defines the context of the *Risk*, (i.e., specifies whether the *Risk* is associated with the entire system, or focused on a part of it). Note: All SCE assets within CPUC designated HFRA are exposed to Wildfire, PSPS, and PEDS risk. In non-HFRA, SCE's assets may be exposed to some or all of these risks.
- ***Driver*** is a factor that could influence the likelihood of a *Risk Event*. A Driver may include external events or characteristics inherent to the asset or system.
- ***Likelihood*** *or* ***Probability*** refers to the relative possibility that an event will occur, quantified as a number between 0% and 100% (where 0% indicates impossibility and 100% indicates certainty). The higher the Probability of an event, the more certain that the event will occur. LoRE is an acronym for "Likelihood of a Risk Event." Note: SCE calculates likelihoods of wildfire, PSPS, and PEDS risk. See Section 5.2 for additional detail.
- ***Risk Event*** is an occurrence or change of a particular set of circumstances that may have potentially adverse *Consequences* and may require action to address. In particular, the occurrence of a *Risk Event* changes to some or all *Attributes* of a risky situation. Note: SCE considers wildfire, PSPS, and PEDS as individual risks. In the case of wildfire ignition risk, the risk event is an ignition associated with SCE overhead electrical equipment in SCE's HFRA. In the case of PSPS and PEDS risks, the risk events are a de-energization event during fire weather conditions when de-energization thresholds are exceeded or protective equipment settings are triggered, respectively.
- ***Frequency*** refers to the number of events generally defined per unit of time. Note: Frequency is not synonymous with Probability or Likelihood.
- ***Outcome*** refers to the final resolution or end result of a Risk Event. Note: SCE considers a range of location specific Fire Behavior Outcomes (FBO) in its Fire Weather Day (FWD) section process to simulate various intensities of wildfire risk events once an ignition has occurred. See Section 5.2 for additional detail.
- ***Consequence*** refers to the impact of an occurrence of a *Risk Event*. These consequences are usually assessed by specific *Attributes* such as safety, financial, or reliability. *Natural Unit Attribute* refer to units of measurement for individual consequence attributes. For example, the *Natural Unit Attribute* of a *Safety Attribute* is the number of fatalities.

Additionally, see Figure SCE 5-02 for the Risk Bowtie describing the components used in SCE's MARS Framework to calculate wildfire risk in a manner consistent with the CPUC RDF. SCE used the OEIS prescribed color scheme to facilitate comparison between OEIS and CPUC components. Each component is described in additional detail in the following section.

Figure SCE 5-02: Risk Bowtie Depicting SCE's MARS Framework Consistent with CPUC RDF[39]



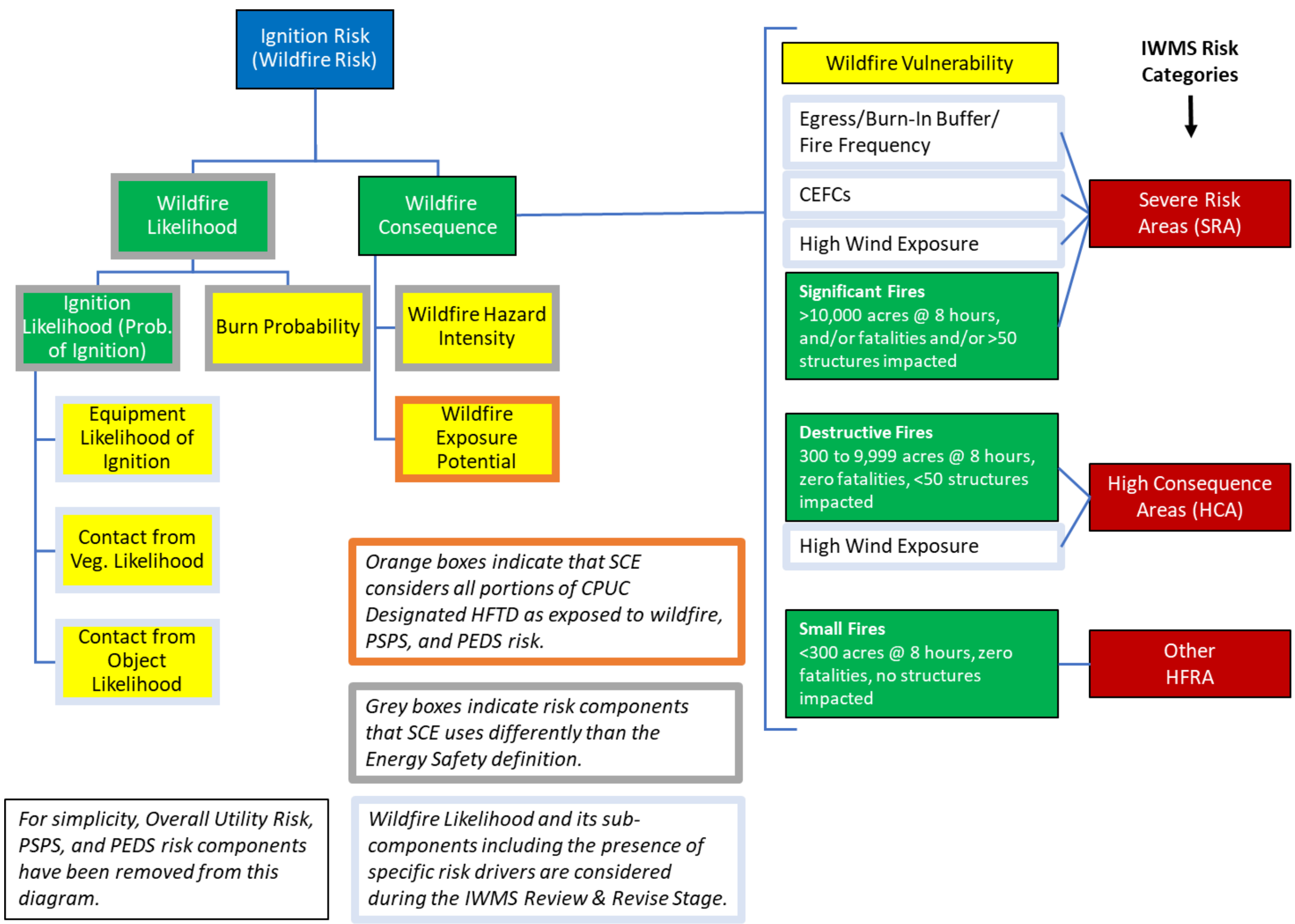
39 CPUC Risk Informed Decision-Making Proceeding R.20-07-013.

5.2.1.2 IWMS Risk Framework

The diagram below depicts SCE's IWMS Risk Framework. SCE's IWMS Risk Framework is used to segment risk based on specific location-based risk factors, which are not fully captured by the MARS methodology. These IWMS categories are: Severe Risk Area (SRA), High Consequence Areas (HCA) and Other Areas (Other).

The figure below (Figure SCE 5-03) depicts how the risk components are used in the IWMS Risk Framework. The colors match how Energy Safety has presented the risk components.

FIGURE SCE 5-03: SCE'S IWMS Risk Framework



The IWMS risk assessment process is comprised of two major stages – an "Initial Risk Categorization" stage, followed by a "Review & Revise" stage. These stages are described below:

5.2.1.2.1 Stage 1: Initial Risk Categorization

In the Initial Risk Categorization stage, SCE qualitatively assesses several location-specific factors to categorize areas within SCE's HFRA into SRA, HCA, and Other. The IWMS risk categories are described below.

- Severe Risk Areas (SRA) are locations characterized by elevated population risk factors such as egress constrained locations, areas with significant wildfire risk, and/or locations with wind conditions that typically exceed covered conductor thresholds.
- High Consequence Areas (HCA) are locations in which simulated wildfires exceed 300 acres[40] and do not contain the population risk factors characterized by SRA or meet or exceed PSPS thresholds for de-energization.
- Other HFRA (Other) encompasses locations within HFRA that do not meet either of the previous criteria. A detailed description of these three risk tranches, including all factors used, is provided below.

5.2.1.2.1.1 Severe Risk Areas

SRA locations are characterized by elevated population risk factors such as egress-constrained locations, areas with significant wildfire risk, and/or locations with wind conditions that typically exceed covered conductor thresholds.

SCE uses the following four criteria[41] to determine SRAs:

- SRA1: Fire Risk Egress Constrained Areas – locations identified based on an index comprised of a high historical fire frequency and population/roadway egress. Additionally, a burn-in buffer around egress locations are modeled to determine which assets, if involved in an ignition, would burn into egress locations within the simulated burn period.
- SRA2: Significant fire consequence – locations with the potential for greater than 10,000 acres burned based on wildfire simulations.
- SRA3: High winds – Locations, which if even fully covered with covered conductor, would still be subject to high PSPS likelihood.
- SRA4: Communities of Elevated Fire Concern – Smaller geographic areas where terrain, construction, and other factors could lead to smaller, fast-moving fires threatening populatedlocations under benign (normal) weather conditions.

SCE notes that individual locations may (and often do) meet multiple SRA criteria.

SRA1: Fire Risk Egress Constrained Areas

The methodology to determine Fire Risk Egress Constrained Areas is comprised of five steps:

i. Divide SCE's HFRA into equally sized polygons.
ii. Identify population egress-constrained locations.
iii. Determine locations that have experienced high historical fire frequency.

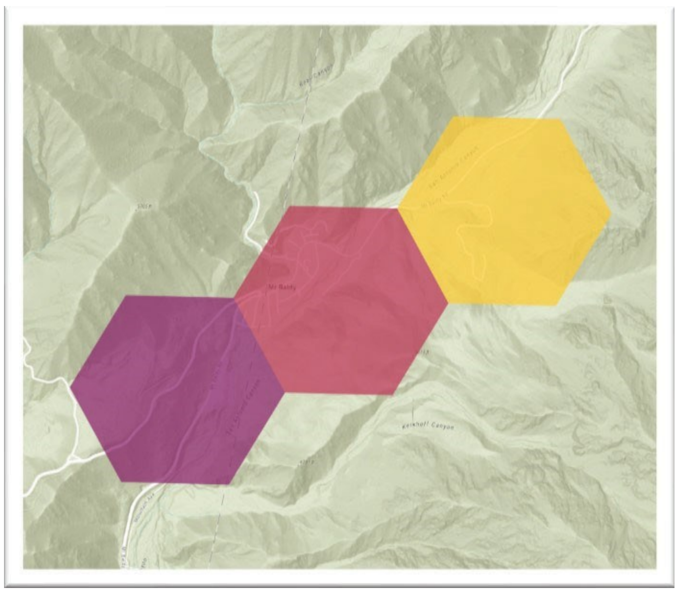
40 Based on a simulated 8-hour truncated wildfire simulation.
41 All IWMS criteria are based on an 8-hour truncated wildfire simulation.

iv. Overlay the egress-constrained locations with high historical fire frequency locations to determine Fire Risk Egress Constrained Areas.

v. Assess risk scores around these Fire Risk Egress Constrained Areas, to determine which locations could burn into Fire Risk Egress Constrained Areas within simulated burn period. Designate these locations as "Burn-in Buffer" locations.

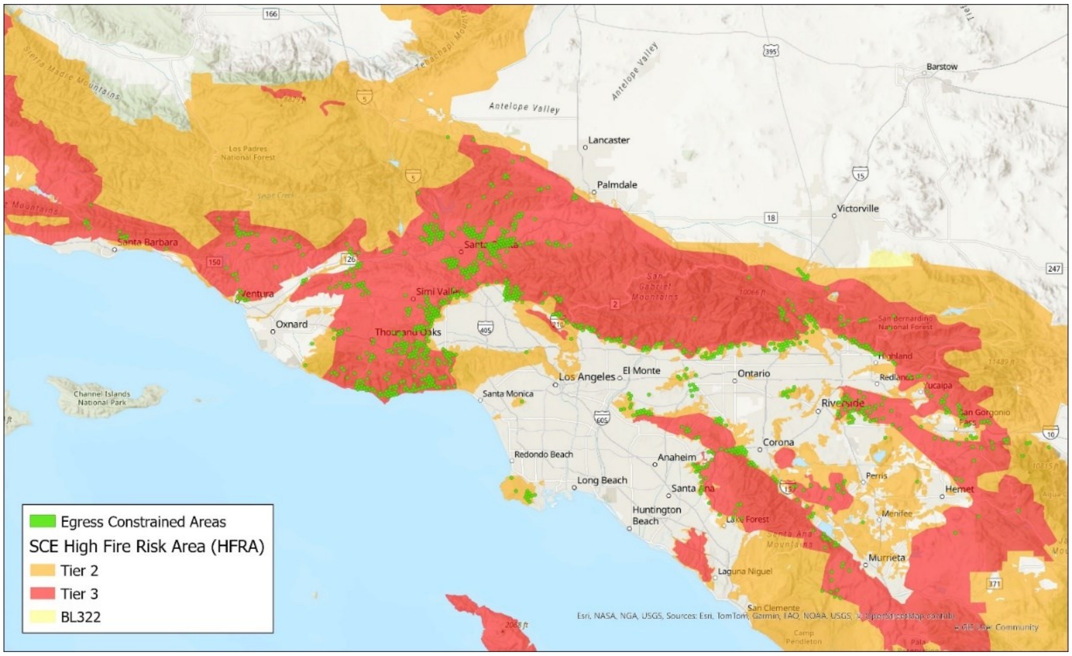
In previous versions of SCE's Wildfire Risk Reduction Model (WRRM), SCE divided its service territory into hexagons approximately 214 acres in size. SCE used hexagons because the distance from the center of a hexagon to all adjacent hexagons is the same distance (1,000 meters) and it enabled SCE to compare variables across similar-sized polygons. In FireSight 8, SCE has aligned to the Uber H3 Hexagon Spatial Hierarchy industry standard. See Section 5.2.2.2.2.4 for additional information.

Figure SCE 5-04: Division of SCE's HFRA into Equally Sized Polygons



SCE used the hexagons to assess population density and road availability. It then compared the ratio of roads to population in its HFRA to create an index of the relative population egress constraints at each location (see Figure SCE 5-05). A lower index score indicates fewer miles of roads available per person. SCE's method assumes that a substantial portion of the people who perish in wildfires face constraints when attempting to evacuate during a wildfire event. Additionally, SCE notes that not all segments of the population have access to personal transportation or are able to evacuate successfully during a wildfire event (e.g., older, younger, infirm, or institutional).

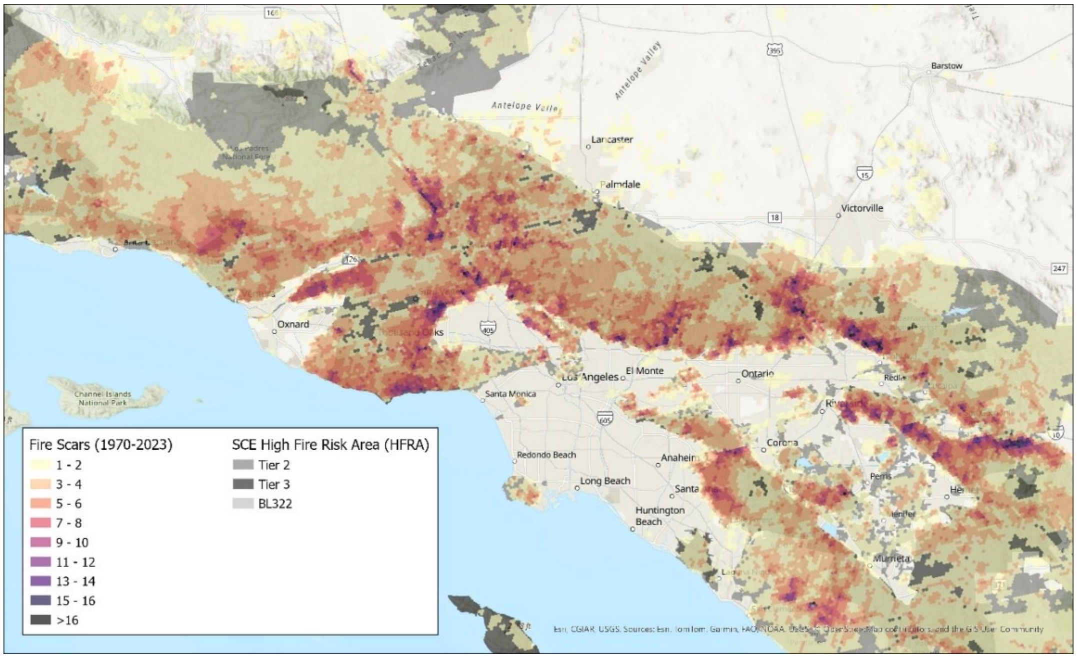
Figure SCE 5-05: Example of Identified Population Fire Risk Egress-Constrained Locations in SCE HFRA



SCE used historical fire perimeters from CAL FIRE's and Resource Assessment Program (FRAP) database to create hexagons[42] to create an index based on the relative fire frequency of each location (see Figure SCE 5-06). A higher score indicates a higher historical fire frequency.

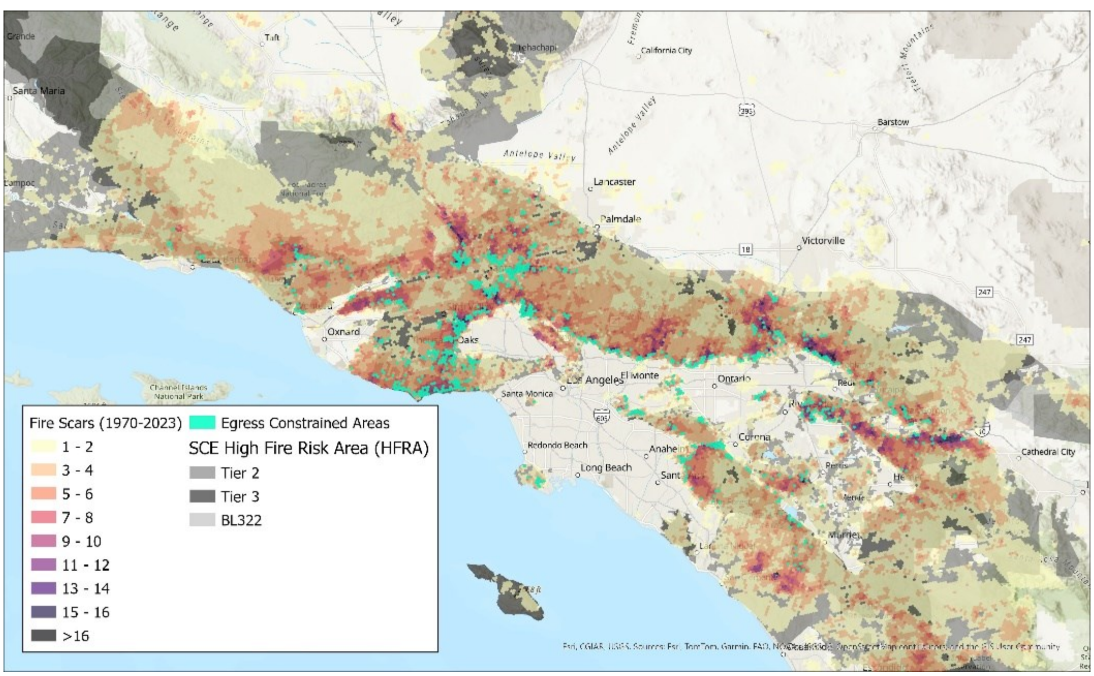
42 Fire perimeters from Cal Fire FRAP database from 1970 to 2020. Fire Frequency hexagons are based on the same hexagon alignment used to identify population egress constrained locations.

Figure SCE 5-06: Identify Areas with a High Historical Fire Frequency in SCE HFRA



SCE then overlaid the population egress-constrained areas with locations that have experienced high historical fire frequency. SCE flagged hexagons with both limited road availability and a high burn frequency based on these indices as potential Fire Risk Egress Constrained Areas.

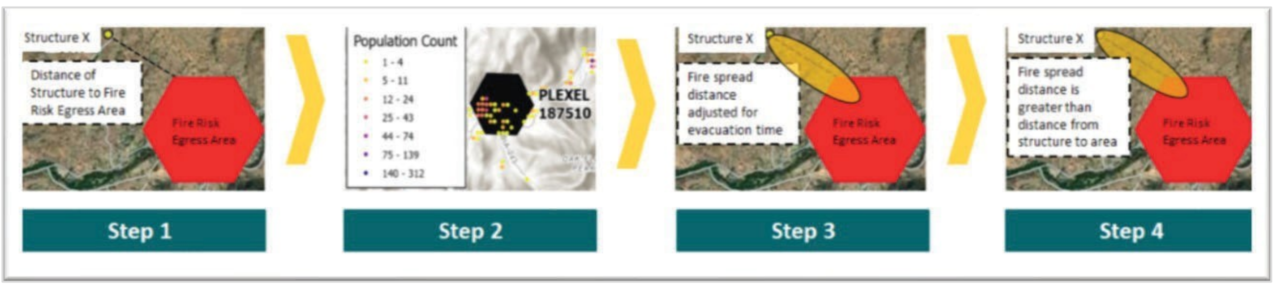
Figure SCE 5-07: Example Overlay of High Historical Frequency of Fires with Fire Risk Egress-Constrained Area in SCE HFRA



Next, SCE used simulated wildfire risk scores around these Fire Risk Egress Constrained Areas, to determine which locations could burn into Fire Risk Egress Constrained Areas within the simulated burn period, using the following steps (see Figure SCE 5-08).

i. Identify all overhead assets within 25 miles of a Fire Risk Egress Constrained Area.
ii. Calculate the time needed for the population to exit the polygon using population size, travel speed, and distance to safety.
iii. Considering terrain and other factors, calculate the distance the fire could travel from each SCE overhead structure within 25 miles, in the time needed to evacuate the Fire Risk Egress Constrained Area.
iv. Flag the overhead assets as a potential burn in buffer location if the fire originating there could enter the Fire Risk Egress Constrained Area.
v. Assess identified locations to confirm burn in buffer location designation, accounting for specific locational factors, such as prevailing wind direction, topography, and physical barriers (e.g., lakes).

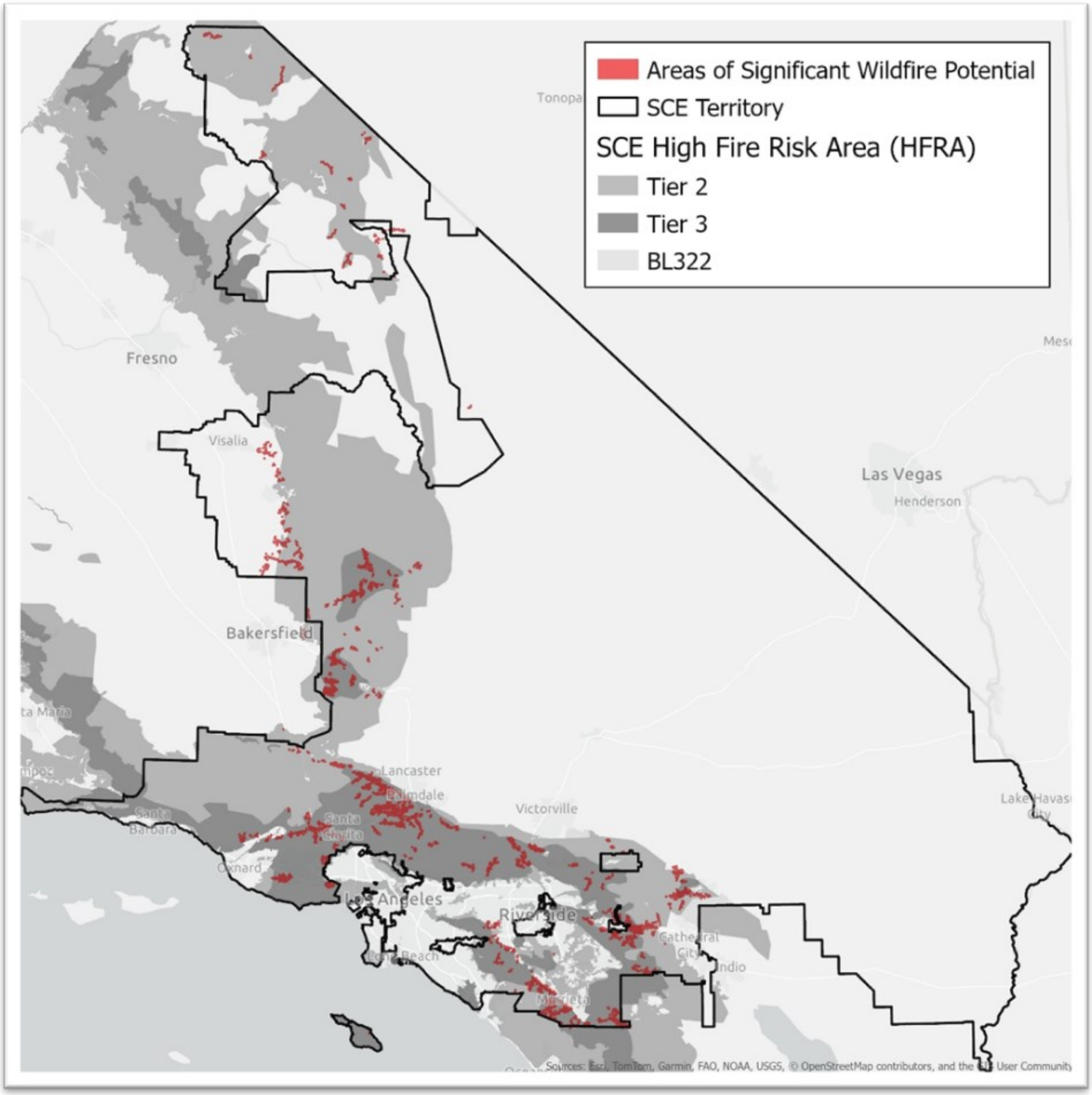
Figure SCE 5-08: Steps to Calculate the "Burn in Buffer"



SRA2: Significant Fire Consequence

SCE identified locations with the potential for greater than 10,000 acres burned (unsuppressed) based on wildfire simulations. SCE used the threshold of 10,000 acres or greater burned in the first 8 hours, given that these fires typically are difficult to suppress and tend to grow exponentially over the next burning period. SCE provides further explanation for this threshold in the High Consequence section.

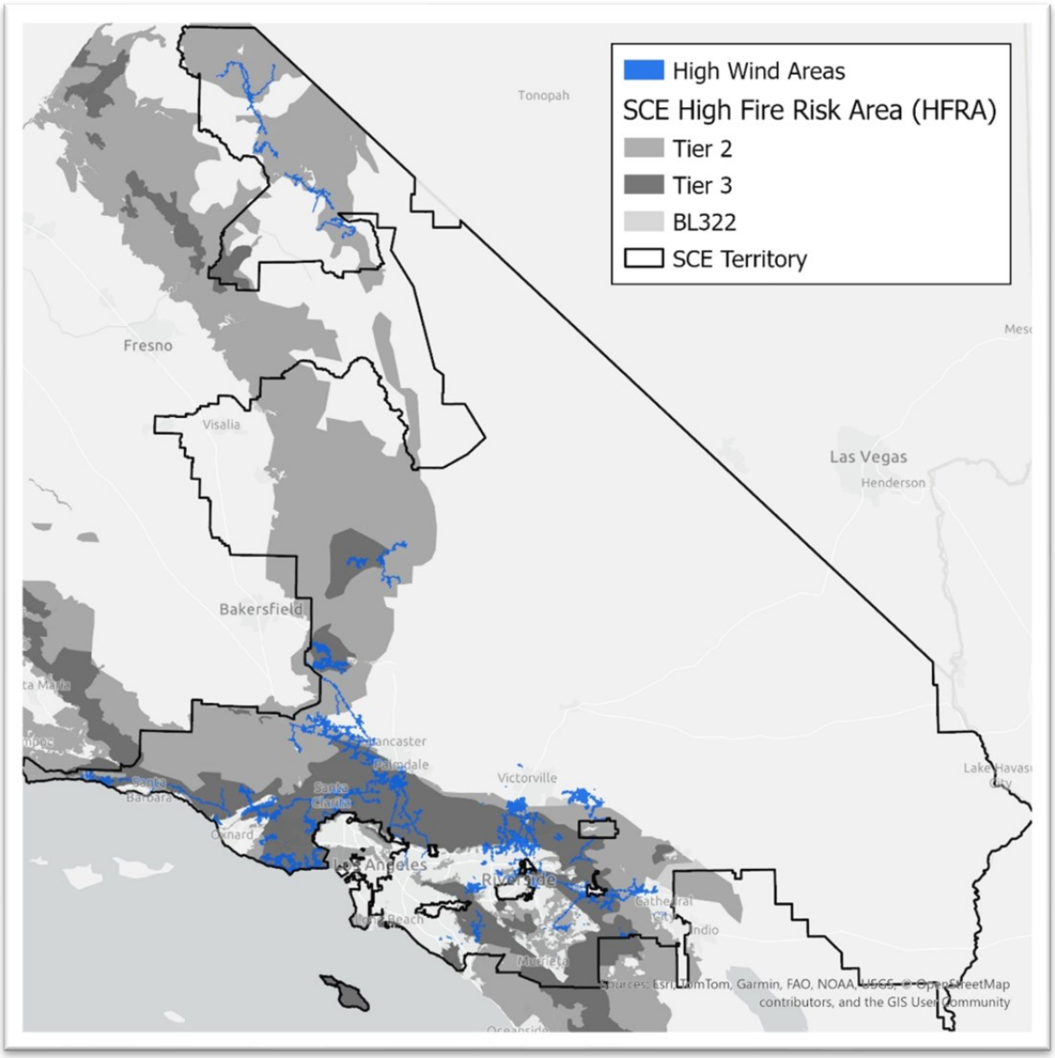
Figure SCE 5-09: Areas with Significant Wildfire Consequence Potential in SCE HFRA



SRA3: High Wind Locations

SCE examined historical wind data from 2017 to determine which areas have experienced high sustained wind speeds above 40 mph and wind gusts above 58 mph (current PSPS de-energization threshold for fully covered isolatable conductor segments).[43] Even if fully covered, the circuit segments in these locations would likely still be subject to a high level of PSPS notifications and de-energization.

Figure SCE 5-10: High Wind Locations in SCE HFRA



SRA4: Communities of Elevated Fire Concern

In addition to the previous criteria, SCE also consulted with internal fire science and external local emergency management officials to identify Communities of Elevated Fire Concern (CEFCs). CEFCs are smaller geographic areas where terrain and other factors could lead to smaller, fast-moving fires to threaten populated locations under benign (normal) weather conditions. Examples of these types of communities are those on the edge of a hill, where, if an ignition were to occur downhill from that community, the ignition could immediately impact those populated locations, even under low to no wind conditions.

43 This may change as SCE modifies thresholds based on further analyses and data over time.

Figure SCE 5-11: Example of a CEFC with Topographical Overview (Left) and Example of Vegetation in Canyon (Right)

Subdivisions on multiple hilltops surrounded by dense vegetation (left picture). Fires that start in canyon (right picture) will burn rapidly uphill towards populated areas.

5.2.1.2.1.2 High Consequence Areas

SCE uses the following three criteria to determine High Consequence Areas (HCA):

- Locations that do not meet any SRA criteria and meets one of the two criteria below.
- Destructive fire consequence – locations in which simulated wildfires exceed 300 acres.[44]
- Locations subject to PSPS de-energization criteria.

Acreage Threshold

SCE determined an ignition which exceeds 300 acres within the first eight hours has a high probability of eventually becoming very large, thereby posing significant risks to people and property.[45]

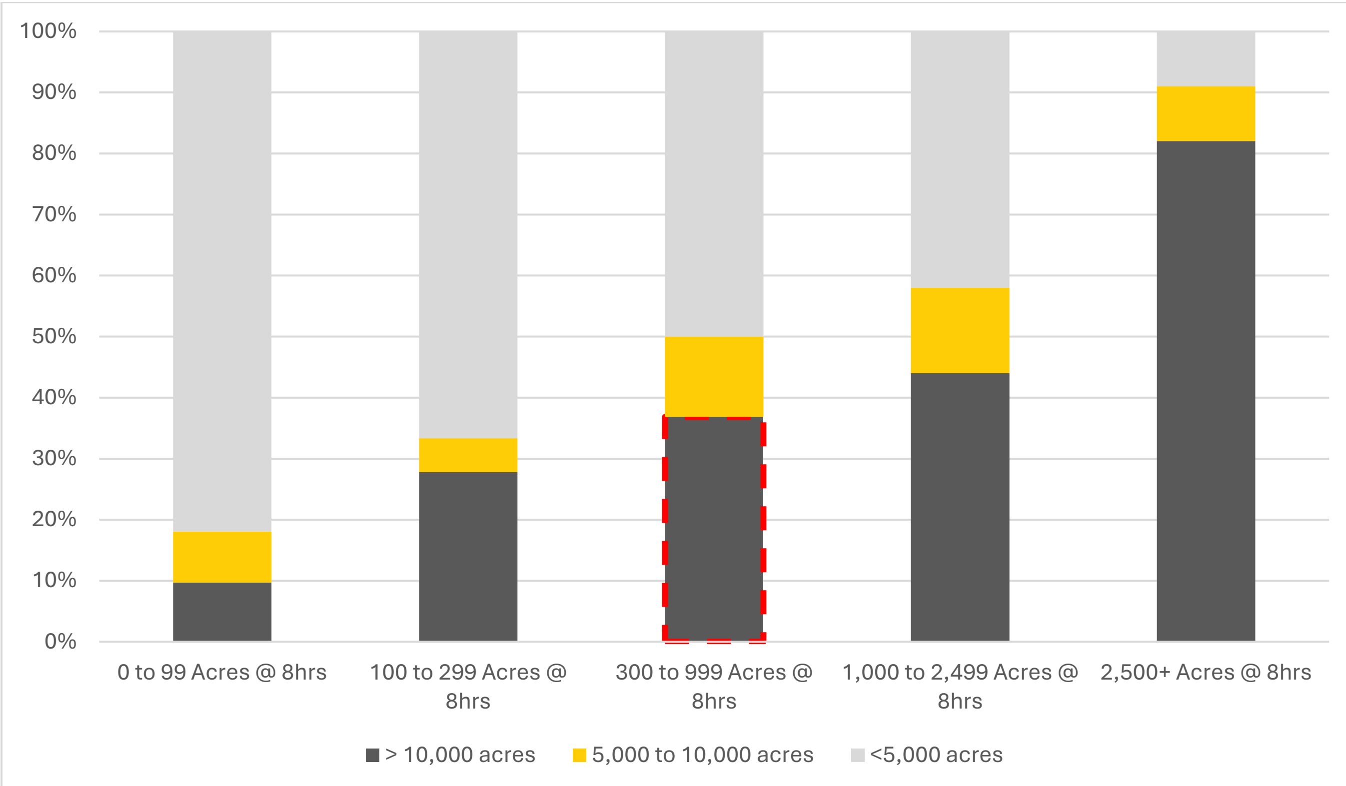
SCE selected the 300 acres burned (High Consequence) and 10,000 acres burned (SRA criteria) thresholds given that number of acres burned is a reasonable and reliable correlated proxy for buildings destroyed. For instance, according to statewide averages from 2015-2019, a fire of 10,000 acres or more destroys approximately 200 buildings.

Additionally, of the wildfires that burned between 300 and 999 acres at 8 hours, 33% eventually burned more than 10,000 acres. In contrast, fires that burned less than 300 acres at 8 hours were much less likely to eventually burn more than 10,000 acres. Of the fires that burned less than 300 acres, only 10% eventually burned more than 10,000 acres. Based on this analysis, SCE selected 300 acres as the lower threshold for modeled fire consequence for HCA.

44 Based on a simulated 8-hour truncated wildfire simulation.

45 As an additional data point, CAL FIRE's FRAP database and CAL FIRE Annual Redbook reports typically only record wildfires in excess of 300 acres to distinguish between small ignitions and small wildfires.

Figure SCE 5-12: Fire Size at 8 Hours Relative to Final Fire Size, 2018-2024



5.2.1.2.1.3 Other HFRA

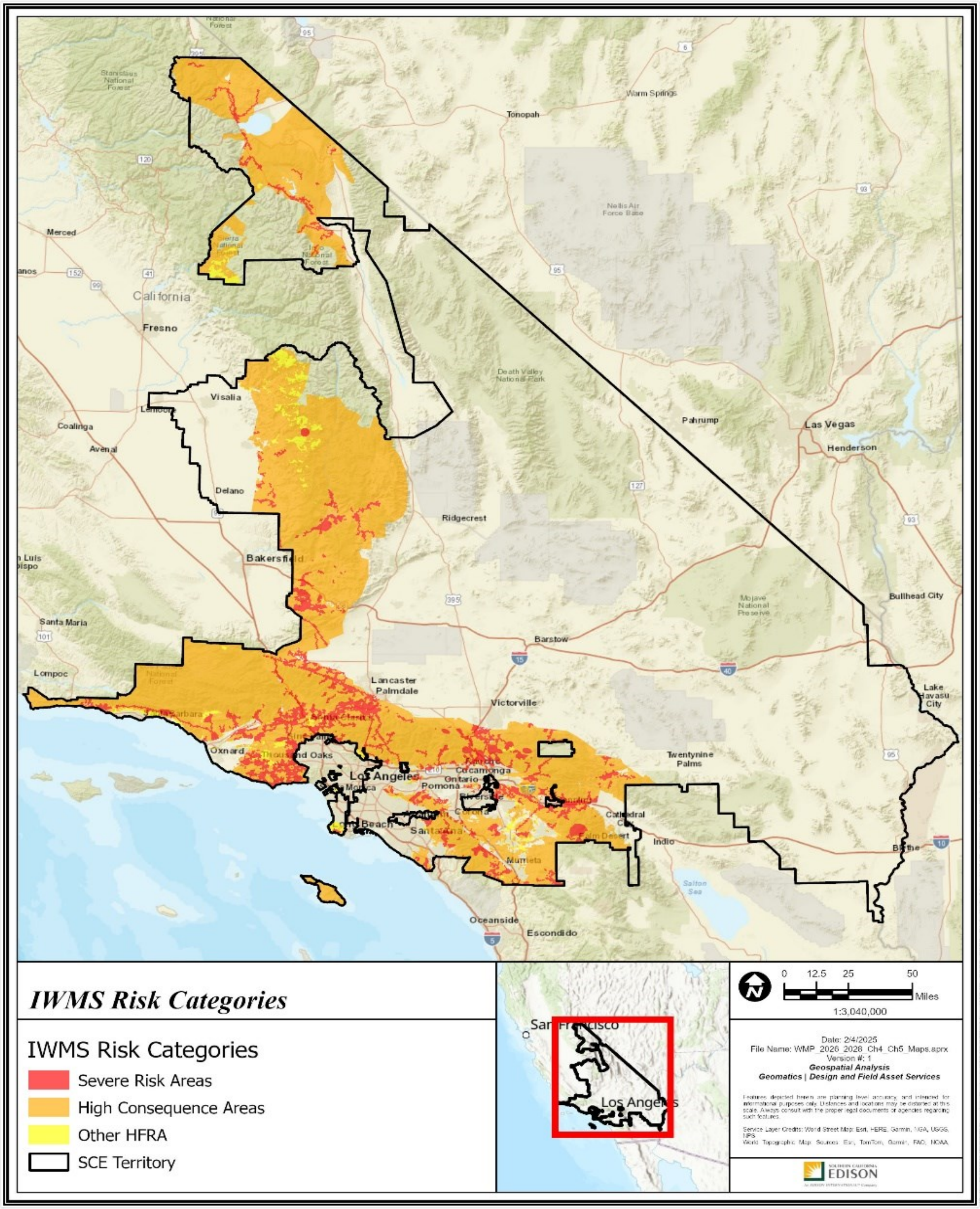
SCE defines "Other HFRA" as locations within SCE's HFRA that are categorized as neither SRAs nor HCA, but as designated in CPUC High Fire Threat District (HFTD) maps as areas of either "extreme" and "elevated" wildfire risk. Additionally, these areas are checked to ensure that they have the potential for less than 300 acres burned based on wildfire simulations. These locations are still subject to regulatory and compliance requirements for enhanced mitigation activity, such as increased inspections and/or vegetation management.

Table SCE 5-02: Summary of IWMS Risk Categories

Severe Risk Area (SRA) Criteria
Fire Risk Egress Constrained Areas – locations identified based on an index comprised of a high historical fire frequency and population/roadway egress. Additionally, a burn-in buffer around egress locations are modeled to determine which assets, if involved in an ignition would burn into egress locations within the simulated burn period. Significant fire consequence – locations with the potential for greater than 10,000 acres burned based on wildfire simulations. High winds – Locations, which if even fully covered with covered conductor, would still be subject to high PSPS likelihood. Communities of Elevated Fire Concern (CEFCs) – Smaller geographic areas where terrain, construction, and other factors could lead to smaller, fast-moving fires threatening populated locations under benign (normal) weather conditions.
High Consequence Area (HCA) Criteria
Locations that do not meet any SRA criteria. Destructive fire consequence – locations in which simulated wildfires exceed 300 acres. Locations that have been subject to PSPS de-energizations.
Other HFRA Criteria
Locations that do not meet either SRA or HCA criteria. Small fire consequence - locations with the potential for less than 300 acres burned based on wildfire simulations.

The following map depicts SRA, HCA, and Other HFRA in SCE's HFRA.

Figure SCE 5-13: Map of SCE IWMS Categories in HFRA[46]



46 Map as of 02/05/2025. SCE provides spatial data at www.sce.com/wmp.

Please see below for Table SCE 5-02a, which shows SCE's total overhead HFTD miles broken out by IWMS risk tranche. This data uses SCE's WRRM 7.6 risk model, which was the model iteration used for 2026-2028 WMP mitigation planning. The circuit mileage data in the table matches the information that SCE transmitted to Energy Safety in Response to Data Request 1, Question 1, which shows 3,218 circuit miles in Severe Risk Areas (SRA).

Table SCE 5-02a – Circuit Miles Per IWMS Risk Tranche

IWMS Risk Tranche	Approximate Circuit Miles
Severe Risk Areas	3,218
High Consequence Areas	4,466
Other HFRA	1,659
Total	9,343

As SCE continuously enhances risk modeling inputs and iterations of its risk model, IWMS risk tranche output miles are subject to change. Since the 2023-2025 WMP, SCE's revised risk model incorporated more granular simulations, included an updated fuel model, adjusted asset locations, and enhanced metrics such as fire behavior and wind speeds. Please see SCE's 2025 Wildfire Mitigation Plan Update for more details about updates to risk models since the filing of the 2023-2025 WMP.

Changes to mileage and IWMS designation are also possible during SCE's Review & Revise process, which is discussed in Section 5.2.1.2.2 of SCE's 2026-2028 WMP. This expert-led analysis evaluates local conditions on a project-by-project basis to validate modeled outputs. In certain instances, SCE's inspection photos, geographic information system (GIS), and Google Maps or Street Views, along with local area knowledge from engineers, fire scientists, and emergency operations professionals, including partners such as CAL FIRE, may contradict model outputs. In that case, the recommendation from the detailed SME review would be to convert the SRA designation to a different IWMS designation, or vice versa.

Since the 2023-2025 WMP, the total number of circuit miles designated as Severe Risk Areas has increased based on mileage updates associated with the four main SRA criteria: (1) fire risk egress constrained areas, (2) significant fire consequence, (3) extremely high winds, and (4) communities of elevated fire concern. These changes are explained below.

- Fire Risk Egress Constrained Areas: Increased by approximately 130 miles
- Significant Fire Consequence: Increased by approximately 280 miles
- Extremely High Winds: Decreased by approximately 165 miles
- Communities of Elevated Fire Concern: Decreased by approximately 85 miles

These updates resulted in the following changes to the circuit miles associated with each IWMS risk tranche between the 2023-2025 WMP and the 2026-2028 WMP:

- a net increase in total SRA mileage from approximately 2,950 circuit miles to 3,218 circuit miles.
- a net increase in total High Consequence miles from approximately 4,400 circuit miles to 4,466 circuit miles.
- a net decrease in Other HFRA miles from approximately 2,250 circuit miles to 1,659 circuit miles.

Note that SRA miles can meet multiple criteria of the four criteria above. For example, a circuit mile might reach the Significant Fire Consequence threshold and be egress constrained. If modeling updates result in that mile no longer displaying significant consequence, those overall miles could go down, but the total SRA mileage would not change because the circuit in question is still egress constrained. For that reason, overall SRA mileage change is not equivalent to the net change from the four presented SRA criteria.

See below for a comparison of SRA, High Consequence, and Other HFRA miles from 2023-2025 and 2026-2028.

Table RN-SCE-26-02–Circuit Miles Per IWMS Risk Tranche by Recent WMP Cycle

IWMS Risk Tranche	Approximate Circuit Miles
Severe Risk Areas	3,218
High Consequence Areas	4,466
Other HFRA	1,659
Total	9,343

5.2.1.2.2 Stage 2: Review & Revise

With exception of CEFC identification process, the first stage of IWMS is reliant upon the completeness, granularity, and accuracy of underlying data sources from which the models are constructed. While these models are valuable as a directional starting point, subject matter expert (SME) judgment is needed to ensure the model matches reality. Accordingly, SCE reviews the output of these models alongside SCE's inspection photos, geographic information system (GIS), and Google Maps or Street Views, along with local area knowledge from engineers, fire scientists, and emergency operations professionals, including partners such as CAL FIRE. These location-specific reviews allow SCE's employees to virtually "walk the line" to ensure a segment is appropriately categorized.

Stage 2 of IWMS is time-consuming and labor intensive, requiring SCE personnel to inspect and review data on hundreds of circuit miles of overhead distribution lines. During these reviews, SCE looks for the presence of risk drivers that include, but are not limited to: heavy trees, long span, local fuel regime, prevailing wind direction and intensity, topography (slope and terrain complexity), local fire ecology, local road accessibility, and existing mitigations (e.g., covered conductor). SCE then makes the determination to either keep the designation as prescribed by the model or recommend an alternate designation as appropriate. SCE concluded its Review & Revise stage in 2024.

Figure SCE 5-14 below shows an example of a 100% match between the initial output (left picture) and detailed SME review (right picture). This location was identified as SRA due to the exceptionally high wildfire consequence score. The model indicated that a fire starting in this location has the potential to grow larger than 10,000 acres in size in the first eight hours. SME review confirmed the location of the overhead lines in relation to the dry, heavy vegetation in the area, topography, and potential winds could lead to a fire of this size.

Figure SCE 5-15 shows one of many Google Maps screenshots of the location marked with the teal circle in Figure SCE 5-14 that SMEs reviewed, confirming the designation as a SRA.

Figure SCE 5-14: Example of 100% Match of Risk Model and SME Review

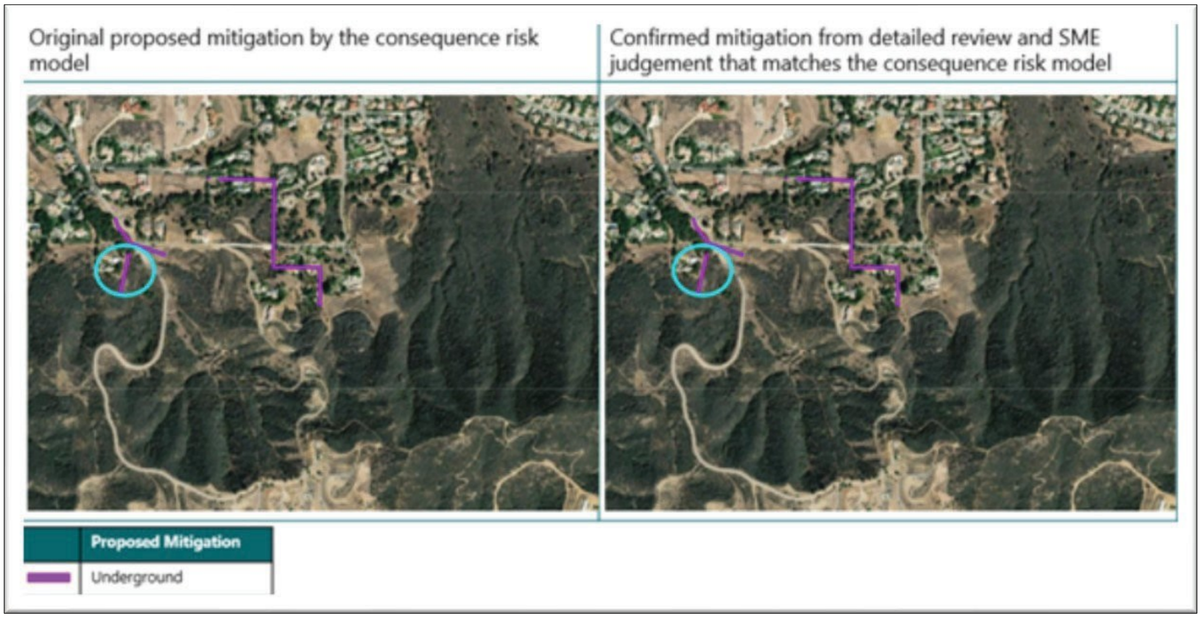


Photo on the left shows initial output of consequence risk model for the location marked with a teal circle. Photo on right shows that the mitigation for the location in the teal circle is 100% confirmed after detailed SME review.

Figure SCE 5-15: Photo of Location Confirms SRA Designation

One of many Google Maps screenshots of the location marked with the teal circle in Figure SCE 5-14 that SMEs reviewed, confirming the designation as a SRA.

Figure SCE 5-16 shows an example of a deviation between the initial IWMS modeled output (left picture) and the subsequent detailed SME review (right picture). The initial output flagged these circuit segments as SRA because they fit the criteria of egress constrained and burn-in buffer.

However, during SME review, it became apparent that the overhead lines mainly run over dirt, roads and light brush and relatively fewer structures in the area would be threatened by a wildfire. The recommendation from the detailed SME review for this location was to convert the designation to a lower HCA designation. Figure SCE 5-17 shows one of many Google Maps screenshots of the location that SMEs reviewed, confirming the need to convert the designation from SRA to HCA.[47]

Figure SCE 5-16: Example of a Deviation Between Risk Model and SME Review

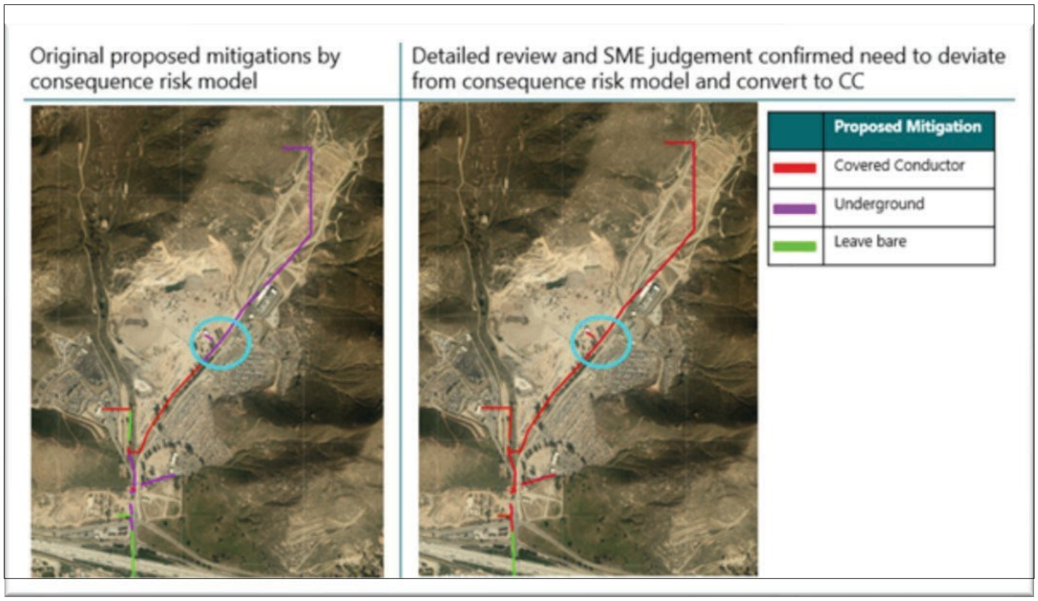


Photo on the left shows the initial IWMS modeled output. Photo on the right shows a different recommended output after detailed SME review.

47 Figure SCE 5-17 is a screenshot of the location marked with a teal circle in Figure SCE 5-16.

Figure SCE 5-17: Photo of Location Confirms Need to Convert Designation from SRA to HCA

During SME review, it became apparent that the overhead lines mainly run over dirt, roads and light brush and relatively fewer structures in the area would be threatened by a wildfire. The recommendation from the detailed SME review for this location was to convert the designation to a lower HCA designation.

Based on the results of the IWMS Review and Revise stage, SCE selects the appropriate mitigation(s) todeploy to each area. SCE details this aspect of the IWMS in Section 5.2.1.2.2.

5.2.1.3 Individual Hazard Risks

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

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

Outage program risk: *The measure of reliability impacts from wildfire mitigation related outages at a given location*

R1: Overall Utility Risk: Overall Utility Risk is calculated as the sum of wildfire and outage program (PSPS and PEDS outage) risk. Overall utility risk is broken down into two individual hazard risks:

R2: Wildfire Risk: Wildfire Risk is calculated as the product of the sum of all Ignition Likelihood components and Wildfire Consequence.

R3: Outage Program Risk: Outage Program Risk is calculated as the sum of PSPS risk and PEDS risk.

5.2.1.4 Intermediate Risk Components

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

IRC1: Wildfire likelihood: SCE considers Wildfire likelihood to be synonymous with Ignition Likelihood. Probability of Ignition (POI) is used to understand both the probability an ignition involving utility assets may occur (i.e., ignition likelihood), as well as the fraction those ignition events may transition to wildfire events (i.e., wildfire likelihood). See Section 5.2.2.2.2.2 for additional information regarding SCE's Fire Weather Day (FWD) selection methodology.

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

IRC2: Ignition likelihood: SCE uses POI to understand both the probability an ignition involving utility assets may occur (i.e., ignition likelihood), as well as the fraction of those ignition events that may transition to wildfire events (i.e., wildfire likelihood). POI is the combined probabilities of Equipment caused ignition likelihood, contact from vegetation ignition likelihood, and contact from object ignition likelihood.

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

IRC3: Wildfire consequence: Wildfire consequences are based on the simulated natural unit consequences (i.e., reliability, financial, as well as safety). Safety risk scores are enhanced based on an Access and Functional Needs (AFN)/ Non-Residential Critical Infrastructure (NRCI) multiplier to account for wildfire vulnerability. SCE does not consider wildfire hazard intensity directly in this calculation. See Section 5.2.2.2.2.2 for additional information regarding SCE's FWD selection methodology. SCE considers all assets within its HFRA exposed to either elevated or extreme wildfire risk.

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

IRC4: PSPS risk: PSPS risk is calculated as the product of PSPS Likelihood (synonymous with Probability of De- energization (POD)) and PSPS Consequence.

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

IRC5: PSPS likelihood: PSPS likelihood is synonymous with PSPS POD.

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

IRC6: PSPS consequence: PSPS outage consequences are based on the estimated natural unit consequences (i.e., reliability, financial, as well as safety). Safety risk scores are enhanced based on an AFN/NRCI multiplier to account for PSPS outage vulnerability. SCE considers all assets within its HFRA exposed to either elevated or extreme wildfire risk, and therefore PSPS risk. In non-HFRA, SCE's assets may be exposed to some or all of these risks.

PEDS outage risk: *The total expected annualized impacts from outages when PEDS was enabled at a specific location.*

IRC7: PEDS outage risk: SCE considers Fast Curve Settings to be part of OEIS' categorization of protective equipment and device settings (PEDS). When Fast Curve Settings are enabled, Fast Curve does not increase the frequency of outages resulting from faults but may impact the size of an outage. The size of an outage influences the number of customers impacted and the time needed to patrol lines before power can be restored. PEDS outage risk is calculated as the product of PEDS outage likelihood and PEDS outage consequence.

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

IRC8: PEDS outage likelihood: The estimate of the projected frequency of outages occurring while PEDS are enabled.

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

IRC9: PEDS outage consequence: PEDS outage consequences are based on the estimated natural unit consequences (i.e., reliability, financial, as well as safety). Safety risk scores are enhanced based on an AFN/NRCI multiplier to account for PEDS outage vulnerability. SCE considers all assets within its HFRA exposed to either elevated or extreme wildfire risk, and therefore PEDS risk. In non-HFRA, SCE's assets may be exposed to some or all of these risks.

5.2.1.5 Fundamental Risk Components

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

FRC1: Equipment caused ignition likelihood: SCE considers Equipment likelihood to be synonymous with Equipment Facility Failure (EFF) POI to understand both the probability an ignition involving utility assets may occur (i.e., ignition likelihood), as well as the fraction those ignition events may transition to wildfire events (i.e., wildfire likelihood). See Section 5.2.2.2.2.2 for additional information regarding SCE's FWD selection methodology.

Contact from vegetation ignition likelihood: *The likelihood that vegetation will contact electrical corporation-owned equipment and result in an ignition.*

FRC2: Contact from vegetation ignition likelihood: SCE considers Contact from vegetation ignition likelihood to be synonymous with Contact from Object – Vegetation (CFO-Veg.) POI to understand both the probability an ignition involving utility assets may occur (i.e., ignition likelihood), as well as the fraction those ignition events may transition to wildfire events (i.e., wildfire likelihood). See Section 5.2.2.2.2.2 for additional information regarding SCE's FWD selection methodology.

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

FRC3: Contact from object ignition likelihood: SCE considers Contact from object ignition likelihood to be synonymous with Contact from Object – Other (CFO-Other) POI to understand both the probability an ignition involving utility assets may occur (i.e., ignition likelihood), as well as the fraction those ignition events may transition to wildfire events (i.e., wildfire likelihood). See Section 5.2.2.2.2.2 for additional information regarding SCE's FWD selection methodology.

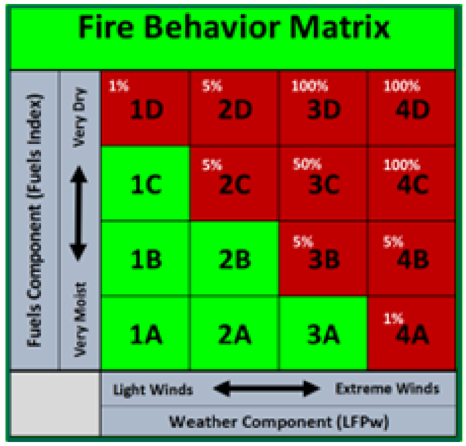
Burn likelihood: *The likelihood that a wildfire with an ignition point will burn at a specific location within the service territory based on a probabilistic set of weather profiles, vegetation, and topography.*

FRC4: Burn likelihood: SCE's wildfire risk model (i.e., FireSight 8) only considers FWDs in which fuel and/or wind conditions are present to produce a wildfire event. These FWDs are selected from SCE's forty-year historical climatology. These selected FWDs are used to simulate ignition events specific to each Fire Climate Zone (FCZ) within SCE's service territory. For completeness, therefore, SCE considers Burn likelihood as an assumed probability of "1."

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

FRC5: Wildfire hazard intensity: SCE's wildfire risk model (i.e., FireSight 8) considers FWDs in which an ignition *could* result in a significant wildfire event. FCZ represent regions within SCE's service territory with homogenous weather, vegetation, topography, and fire history. Using SCE's Fire Behavior Matrix (see below), SCE selects FWD that are substantially dry, windy, or a combination of dry and windy Fire Behavior Outcomes (FBO), that are germane to each unique FCZ, and can result in a wildfire event. SCE then performs simulations across all the selected FWD's at each ignition point. The results produce a full distribution of wildfire consequences, ranging from "0" consequences to higher ranges of consequences, truncated based on the simulation time selected. The resulting consequences can then be adjusted based on the ratio of FWD for each FBO specific to each FCZ over the full forty-year climatology to derive a quasi-probabilistic distribution of outcomes without compromising the integrity of the underlying simulations. See Appendix B FWD selection methodology for additional information, as well as SCE response to SCE-25U-01. Calculating Risk Scores Using Maximum Consequence Values for additional details regarding this approach. See Section 5.2.2.2.2.2 and Appendix B: Supporting Documentation for Risk Methodology and Assessment for additional details. FBM is also used to make operational decisions and will be used for SCE's FPI 2.0 in the future (please refer to Section 10.1.1 for more information).

Figure SCE 5-18: SCE Fire Behavior Matrix (FBM)



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

FRC6: Wildfire exposure potential: SCE does not have a separate risk component for Wildfire Exposure Potential. SCE considers all assets within its HFRA exposed to either elevated or extreme wildfire risk. In non-HFRA, SCE's assets may be exposed to some or all of these risks.

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

FRC7: Wildfire vulnerability: SCE adjusts the safety risk scores based on an AFN/NRCI multiplier to account for the relative social vulnerability of individual circuits compared to the social vulnerability of the total population of circuits within SCE's HFRA. SCE does not directly consider the age of structures or firefighting capacity within this component.

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.*

FRC8: PSPS exposure potential: SCE does not have a separate risk component for PSPS Exposure Potential. SCE considers all assets within its HFRA exposed to either elevated or extreme wildfire risk, and therefore PSPS risk. In non-HFRA, SCE's assets may be exposed to some or all of these risks.

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

FRC9: Vulnerability of community to PSPS (PSPS vulnerability): SCE adjusts the safety risk scores based on an AFN/NRCI multiplier to account for the relative social vulnerability of individual circuits compared to the social vulnerability of the total population of circuits within SCE's HFRA. SCE does not directly consider poor energy resiliency or low socioeconomic – aside from the existing AFN characteristics already accounted for – within this component.

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

FRC10: PEDS outage exposure potential: SCE does not have a separate risk component for PEDS outage exposure potential. SCE considers all assets within its HFRA exposed to either elevated or extreme wildfire risk, and therefore PEDS risk. In non-HFRA, SCE's assets may be exposed to some or all of these risks.

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

FRC11: PEDS outage vulnerability: SCE adjusts the safety risk scores based on an AFN/NRCI multiplier to account for the relative social vulnerability of individual circuits compared to the social vulnerability of the total population of circuits within SCE's HFRA. SCE does not directly consider poor energy resiliency or low socioeconomic – aside from the existing AFN characteristics already accounted for – within this component.

Note: SCE has developed a schematic depicting Wildfire Risk modeling for FireSight 8 using the elements from the CPUC Risk Informed Decision-Making Proceeding (Ph III), combined with OEIS prescribed risk components in the form of a risk bowtie (See Appendix B: Supporting Documentation for Risk Methodology and Assessment).

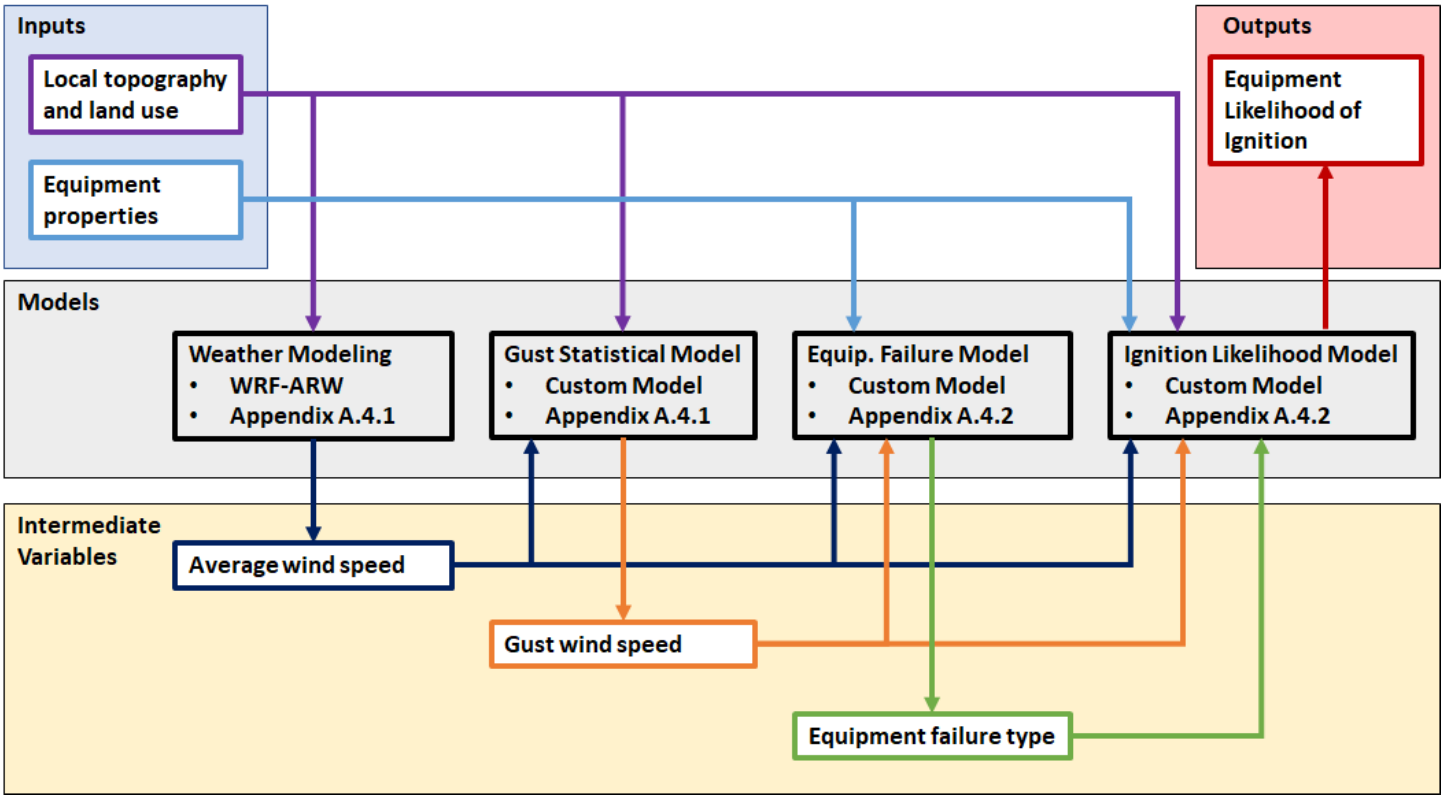
5.2.2 Risk and Risk Components Calculation

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

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

The electrical corporation must provide schematics illustrating the calculation of each risk and risk component as necessary to demonstrate the logical flow from input data to outputs, including *separate items for any intermediate calculations. Figure 5-2 provides an example of a calculation schematic for the equipment likelihood of ignition.*

Figure 5-2: Example of a Calculation Schematic



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

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

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

Diagrams for Risk Components

SCE has developed calculation schematics and input/output diagrams for each required risk component, except for the components in which SCE does not calculate directly or are addressed through other risk components (i.e., Wildfire Likelihood, Burn Probability, Wildfire Hazard Intensity, Wildfire Exposure Potential, PSPS Exposure Potential, and PEDS Exposure Potential).

The diagrams and required additional information for each risk component are provided in Appendix B: Supporting Documentation for Risk Methodology and Assessment.

5.2.2.1 Likelihood of Risk Event

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

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

IRC2: Ignition Likelihood

As described in the previous section, SCE considers Ignition Likelihood to be synonymous with POI to understand both the probability an ignition involving utility assets may occur (i.e., ignition likelihood), as well as the fraction those ignition events may transition to wildfire events (i.e., wildfire likelihood). The pre-mitigated POI for every asset is a probabilistic assessment of Ignition Likelihood prior to mitigation deployment. Each subdriver of ignition is calibrated such that the sum of all asset level POI for a given subdriver equals the total number of ignitions for that subdriver (see Figure SCE 5-20). This allows for the additivity of POI for holistic risk assessment when bundling work or comparing across asset classes. See Section 5.2.2.2.2.2 for additional information regarding SCE's FWD selection methodology.

Figure SCE 5-19: Probability of Ignition Calculation

$$\text{Probability of Ignition} = POI_{EFF} + POI_{CFO\text{-}Veg.} + POI_{CFO\text{-}Other}$$

POI is the combined probabilities of Equipment caused ignition likelihood, contact from vegetation ignition likelihood, and contact from object ignition likelihood. These subcomponent (e.g., EFF, CFO-Veg., CFO-Other) models utilize machine learning (ML) algorithms to assess the relevance of individual ignition drivers relevant to subcomponent. For instance, each EFF related subcomponent model uses historical asset outage data, current asset condition (e.g., age, voltage, inspection results, etc.), and relevant environmental attributes (e.g., historical wind, asset loading, number of customers, temperature, relative humidity etc.). Whereas the CFO-Veg. subcomponent model uses slightly different attributes (e.g., vegetation) to understand the relevant drivers at specific locations. Pursuant to activity RM-1, SCE performs regular data synthesis and quality checks on each of these individual subcomponent models. These subcomponent models are also tested and updated using new observed failures and new inspection, remediation, or replacement information.

Figure SCE 5-20: Schematic for Individual SCE POI Subcomponent Models

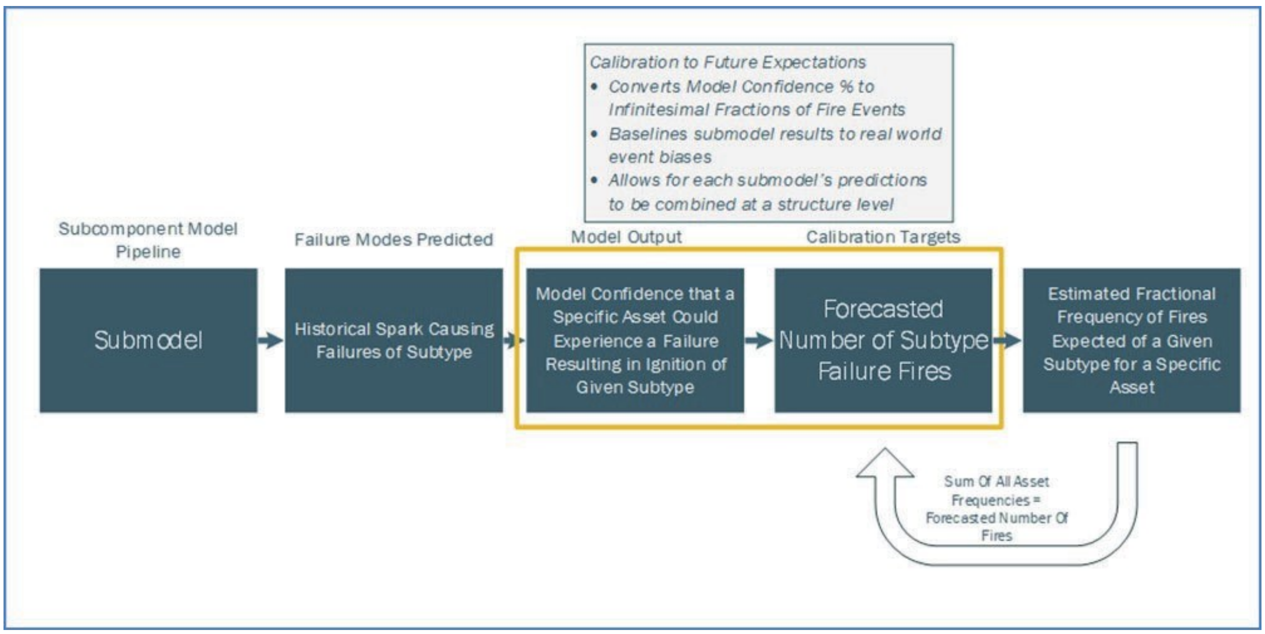
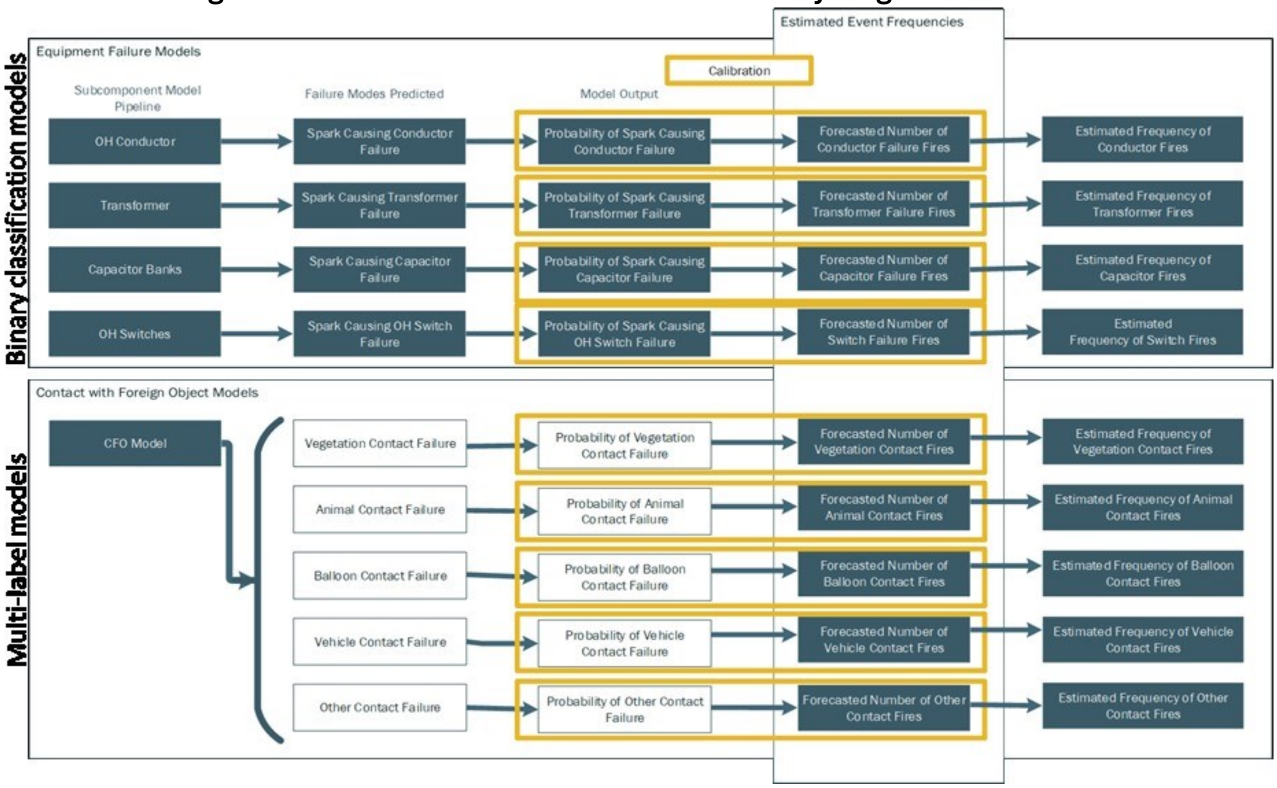


Figure SCE 5-21: Schematic for SCE Probability of Ignition Model



The underlying assumption of these models is that a given set of explanatory data will provide insights into the attributes—specific asset (e.g., age, location, loading, etc.) and environmental (weather, wind, location, maintenance, etc.)—paired with specific outcomes (e.g. actual records of outage and ignition events). Attributes and outcomes data are analyzed using machine learning models to derive statistical insights. Historical attribute and outcome information are divided into a training set and a separate testing set based on a randomly stratified sample for the same time period. The Training set is used to train the model by deriving patterns from the sub model POIs and failure outcomes. The result is a description of the contribution of independent variables (e.g., environmental and/or asset-based) to dependent outcomes (e.g., ignition events). The Test set is then used to compare the results of the training set. Finally, a validation set of data which was not used for either training or testing are used to measure model accuracy by comparing model predictions to actual outcomes. The same process is run periodically to ensure that the accuracy of the model predications has not degraded over time. See Figure SCE 5-22 and Figure SCE 5-23, below.

Figure SCE 5-22: Schematic of POI Subcomponent Model Calculation

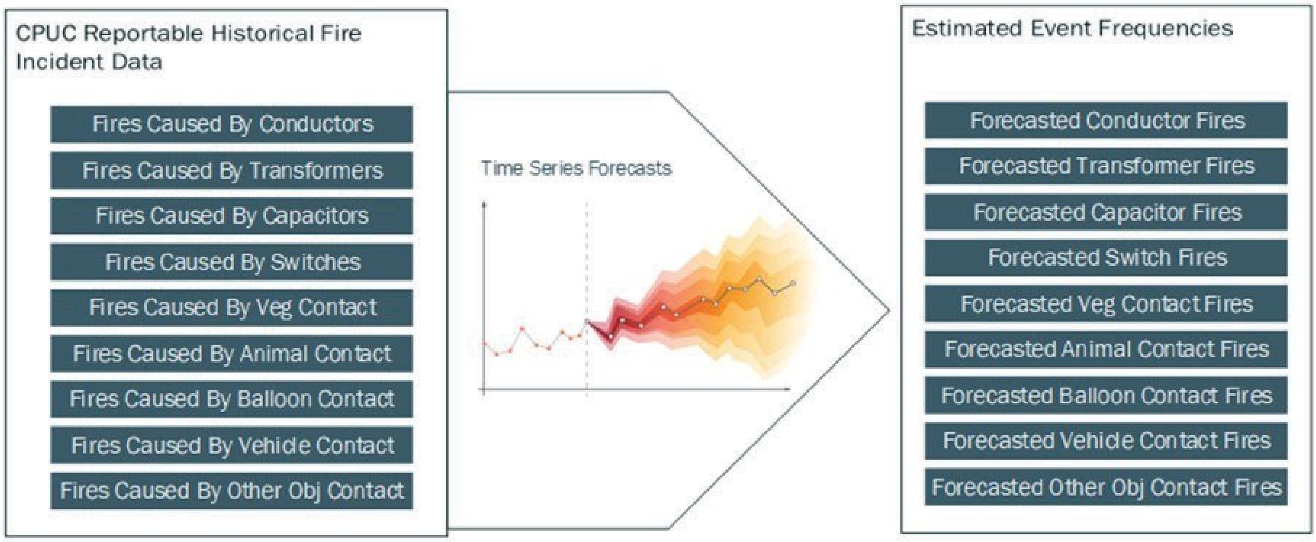
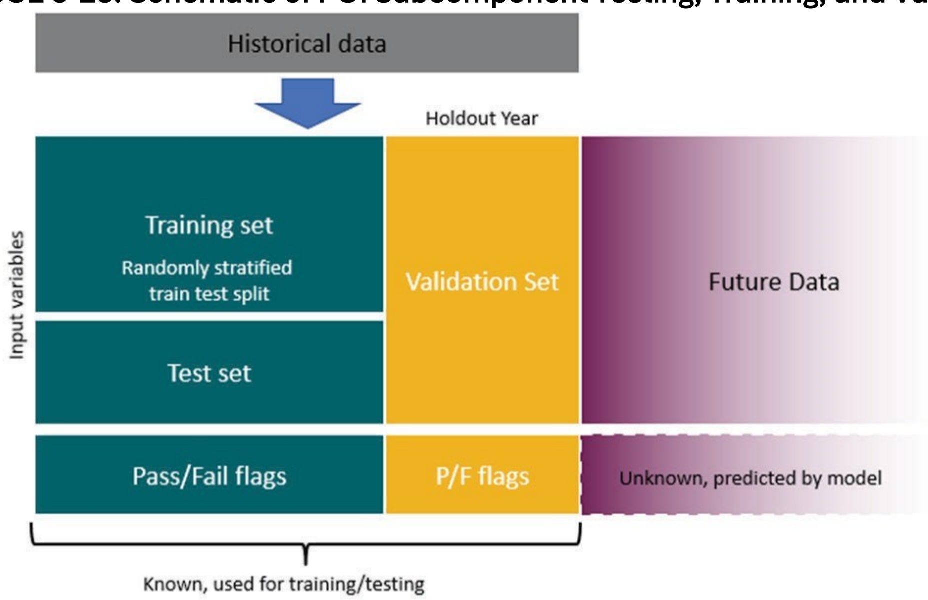


Figure SCE 5-23: Schematic of POI Subcomponent Testing, Training, and Validation



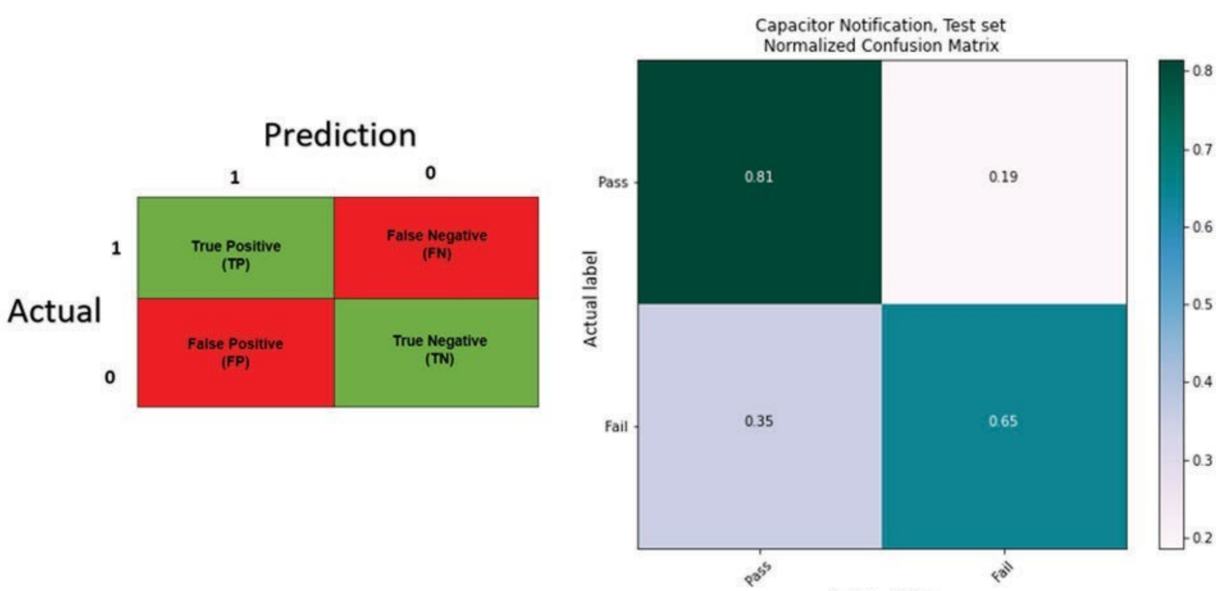
To measure model performance and uncertainty, SCE uses the statistical significance of model and subcomponent model predictions between the training set, testing set, training data set, and the validation data set. In the test set, known historical failures are withheld from model training and the model is “tested” to see if it can predict them. The validation set is used to determine how often the model accurately predicts an ignition event and provides a confidence level on the significance of how individual attributes, or a combination of attributes, are to future predictions of ignition events. SCE utilizes two widely accepted methods of quantifying model performance - the Confusion Matrix (CM) and the Receiver Operating Characteristic (ROC).

The CM (see Figure SCE 5-24, below) is a metric structure that organizes the predictions of a predictive model into buckets based on whether the predictions are correct. The buckets are used to compare correct and incorrect predictions of the algorithm based on a set of known outcome data (e.g., test set data) to determine how often the model predicted failures and non-failures correctly (true positive and true negative rates, respectively), as well as how often the model predicted failures and non-failures incorrectly (false positive and false negative, respectively).

The CM assumes that positive prediction is a correct prediction of an ignition event, and conversely a negative prediction is a correct prediction of a non-ignition event. A “true positive” prediction describes when the model predicts that an ignition is likely to occur, and this prediction reflects the reality that an ignition event did occur in the test set. A “true negative” prediction describes when the model predicts that no ignition event is likely to occur, and this prediction also correctly reflects the reality that an ignition event did not occur in the test set. A “false positive” prediction describes when the model predicts that an ignition is likely to occur, but an ignition did not, in fact, occur in the test set. A “false negative” prediction describes when the model predicts an ignition is unlikely to occur, but an ignition event did occur in the test set.

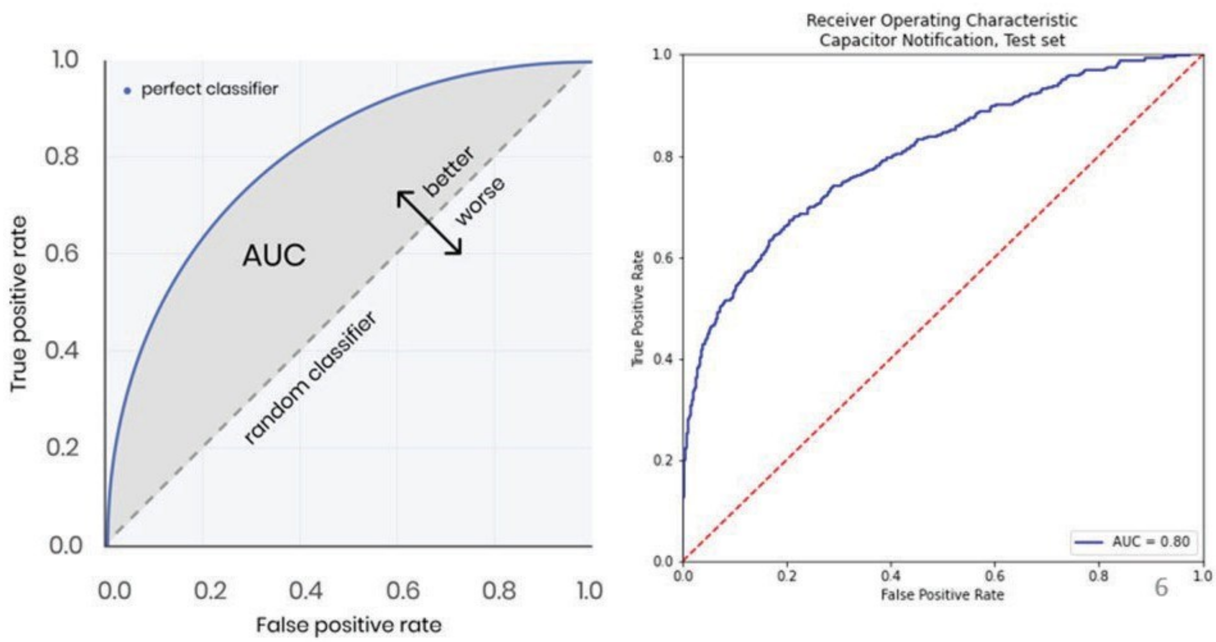
The “true positive rate” of a CM model prediction is also known as the model “sensitivity” or “recall.” The “false positive rate” of a CM model prediction is known as a “Type 1 error.” The “false negative” rate of model prediction is known as a “Type 2 error.” SCE’s machine learning models calculate probabilities for sensitivity, Type 1 errors, and Type 2 errors based on continuum of values from 0 - 100%. Model CM are derived by establishing a model threshold (often 50%) to assess the significance of model predictability. The diagonal elements in the upper left and lower right quadrants in Figure SCE 5-24 denote how often the model was correct, whereas the opposite diagonal elements, in the lower left and upper right quadrants, measure how often the model is incorrect. These matrix results are important in assessing and ranking model performance.

Figure SCE 5-24: Schematic of POI Validation Confusion Matrix



In addition to CM, SCE also uses the ROC curve to measure the accuracy of each subcomponent model to the overall model performance based on selected significance thresholds (see solid blue line in Figure SCE 5-25, below). A ROC is used in addition to the CM, given that there is often a tradeoff in discriminating "true positives" (actual failure predictions) while increasing the rate of "false positives" (false failures) to increase model predictability. The ROC curve is used to reflect the ratio of "true positives" with respect to "false positives" into a single metric by taking the integral of these two metrics and calculating the Area Under the Curve (AUC). If the model were to perfectly classify the train, test, and validation data, the AUC would result in a score of 1.0 (100%) "true positive" result. In a test data set where the model randomly selects a "true positive" result 50% of the time, the AUC would result in a score of 0.5 (50%). This means that the model is no better than a random guess or colloquially a "coin toss," as represented by the dotted red line in Figure SCE-25.

Figure SCE 5-25: Schematic of POI ROC Curve



FRC1: Equipment caused ignition likelihood

SCE considers Equipment likelihood to be synonymous with EFF POI to understand both the probability an ignition involving utility assets may occur (i.e., ignition likelihood), as well as the fraction those ignition events may transition to wildfire events (i.e., wildfire likelihood). EFF POI is the sum of the EFF ignition component submodel (e.g., conductor POI, switch POI, transformer POI, etc.) probabilities at a given location. EFF POI utilizes similar algorithms and model performance metrics as described in the Ignition Likelihood section.

FRC2: Contact from vegetation ignition likelihood

SCE considers Contact from vegetation ignition likelihood to be synonymous with CFO-Veg. POI to understand both the probability an ignition involving utility assets may occur (i.e., ignition likelihood), as well as the fraction those ignition events may transition to wildfire events (i.e., wildfire likelihood). CFO – Veg. POI utilizes similar algorithms and model performance metrics as described in the Ignition Likelihood section.

FRC3: Contact from object ignition likelihood

SCE considers Contact from object ignition likelihood to be synonymous with CFO-Other POI to understand both the probability an ignition involving utility assets may occur (i.e., ignition likelihood), as well as the fraction those ignition events may transition to wildfire events (i.e., wildfire likelihood). CFO – Other POI (e.g., vehicles, balloon, animals, other, unknown, etc.) utilizes similar algorithms and model performance metrics as described in the Ignition Likelihood section.

FRC4: Burn likelihood

SCE's wildfire risk model (i.e., FireSight 8) only considers FWDs in which fuel and/or wind conditions are present to produce a wildfire event. These FWDs are selected from SCE's forty-year historical climatology. These selected FWDs are used to simulate ignition events specific to each FCZ within SCE's service territory. For completeness, SCE considers Burn likelihood has an assumed probability of "1." We believe this methodology is superior to existing probabilistic models which employ burn probability yet tend to lack sufficient granularity to guide the deployment of individual mitigations.[48]

IRC5: PSPS Likelihood

PSPS likelihood is synonymous with PSPS Probability of De-energization (POD). SCE derives PSPS POD by comparing 10+ years of historical weather conditions along distribution circuits to current SCE de-energization thresholds, as well as the state of current and forecasted grid hardening deployment. Historical weather conditions are used to establish a baseline regarding the frequency and duration of de-energization conditions for individual circuits. Mitigation deployment information is used to understand to what degree – in terms of both frequency and duration – current and future mitigation deployment will likely reduce de-energization probability.

SCE used a gridded historical dataset available at a two-kilometer by two-kilometer spatial resolution over the entire SCE territory to derive these historic weather conditions. This gridded dataset provides consistent data coverage and a sufficient period of length to derive the average number of hours each circuit would have exceeded PSPS de-energization criteria in the modeled data using specific PSPS thresholds. This information is used to derive the historical exceedance of circuit de-energization (frequency and duration) conditions based on unhardened de-energization thresholds. SCE then adjusted these de-energization thresholds to simulate current and future grid hardening post mitigation deployment assuming future conditions are similar to historical weather conditions, on average.

SCE notes that this historical weather condition data set is driven by observed historical atmospheric conditions. Terrain and meteorological resolution are constrained to computational limitations. The ability to represent complex terrain is limited, as is representation

48 U.S. Forest Service, Wildfire Risk to Communities Burn Probability. See https://data-usfs.hub.arcgis.com/datasets/d93720867d1a4aa69f4a15dbf3ddeaea/explore?location=34.251879%2C-118.066303%2C9.84

of small-scale weather features that play important factors in determining local wind speeds. Additionally, climate change literature does not definitively point to a likely increase or decrease in potential future high wind conditions. Therefore, there is some uncertainty regarding future weather conditions.

IRC8: PEDS Outage Likelihood

Protective Equipment and Device Settings (PEDS) outage likelihood denotes the probability of an outage occurring on circuits with Fast Curve settings enabled. SCE derived PEDS likelihood by using the last 5-year historical outages on Fast Curve-enabled circuits, while also considering that Fast Curve settings were installed and are enabled at different times of the year. These historical events are used to establish a baseline regarding the frequency and duration of outage conditions on individual circuits, whereas mitigation deployment information is used to understand to what degree – in terms of both frequency and duration – current and future mitigation deployment will likely reduce outage probability.

SCE notes that historical operations are driven by observed historical atmospheric conditions (i.e., Red Flag Warning days). Terrain and meteorological resolution are constrained to computational limitations. The ability to represent complex terrain and represent small-scale weather features that are important in determining local wind speeds are also limited. Additionally, climate change literature does not definitively point to a likely increase or decrease in potential future Red Flag Warning days therefore there is some uncertainty regarding future weather conditions.

5.2.2.2 Consequence of Risk Event

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

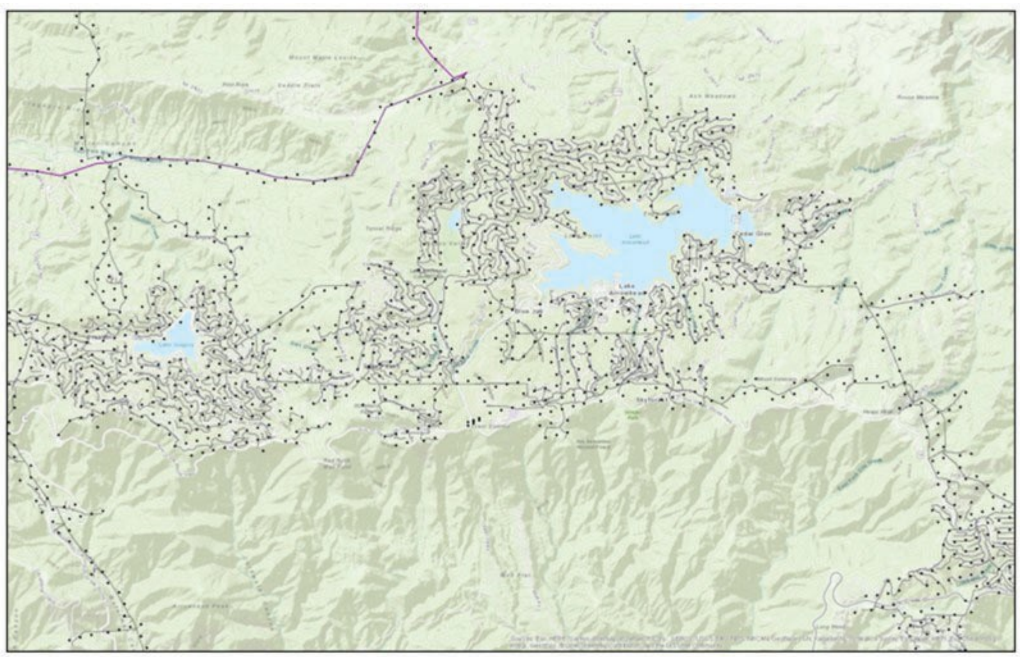
- *Wildfire consequence*
- *Wildfire hazard intensity*
- *Wildfire exposure potential*
- *Wildfire vulnerability*
- *PSPS consequence*
- *PSPS exposure potential*
- *PSPS vulnerability*
- *PEDS outage consequence*
- *PEDS outage exposure potential*
- *PEDS outage vulnerability*

5.2.2.2.1 Wildfire Consequence Risk Component

IRC3: Wildfire Consequence

SCE utilizes Technosylva-based wildfire modeling tools to assess wildfire consequences based on deterministic match-drop simulations at utility asset location (see Figure SCE 5-26). These simulations allow SCE to isolate ignitions associated with wildfire simulations along utility assets and assign the resulting natural unit consequences back to those assets. The use of a consistent unsuppressed burn period allows for direct comparison of the resulting consequences without the underlying bias of other factors found in historical data sets (e.g., the inconsistent deployment and effectiveness of suppression resources).

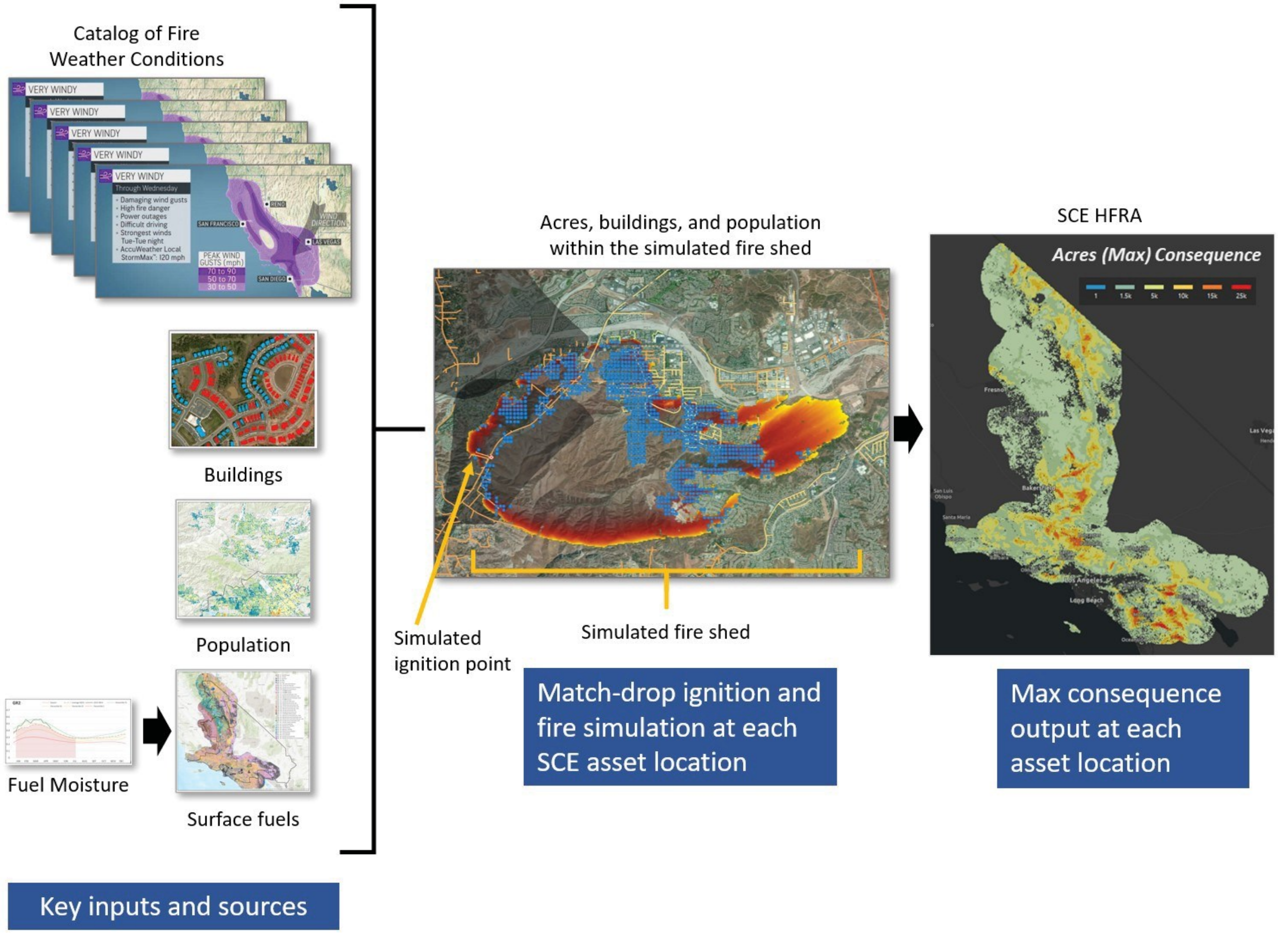
Figure SCE 5-26: Example of Ignition Points (Black Dots) in Proximity to Utility Assets (Gray Lines)



SCE assigns the resulting maximum natural unit consequences (e.g., acres, building, and population) across the simulated weather scenarios to the asset in proximity to match drop simulations using zonal statistics. The resulting natural unit acres and building consequences are translated into financial values (e.g., suppression and restoration costs per acre, and building replacement value).

Natural unit population consequences (e.g., fatalities and serious injuries) are translated into a safety index (e.g., one serious injury equals one quarter of a fatality). SCE also assumes eight hours of customer interruption along the circuit in which the ignition propagated. The resulting reliability values—the product of eight hours of interruption and the number of customers on a given circuit—are used as a conservative estimate of the potential reliability impacts of a resulting wildfire. See Figure SCE 5-27 for a generalized representation of wildfire simulation process.

Figure SCE 5-27: Schematic of SCE Wildfire Consequence Modeling (8 Hours, Unsuppressed)



5.2.2.2.2 Summary of Updates to the Wildfire Consequence Model

This section provides a summary of the updates from WRRM to SCE's FireSight 8 Wildfire Consequence Model. Further supporting information can be found in Appendix B: Supporting Documentation for Risk Methodology and Assessment.

As mentioned in its 2025 WMP Update, SCE committed to exploring methods that would allow it to transition to a quasi-probabilistic wildfire consequence model to better represent fire weather in local regions, while maintaining the integrity of its existing underlying granular wildfire risk modeling architecture (see SCE response to SCE-23-02 Calculating Risk Scores Using Maximum Consequence Values in its 2025 WMP Update, as well as Appendix D: Areas for Continued Improvement: ACI SCE-25U-01 Calculating Risk Scores Using Maximum Consequence Values).

SCE believes the FireSight 8 model accomplishes these objectives. FireSight 8's FCZ- based FWD methodology allows SCE to extract granular consequence distributions at every ignition point (see Figure SCE 5-28, below) and helps SCE to understand how these conditions may change based on future climate conditions (see Section 3.7, as well as Appendix D: Areas for Continued Improvement). ACI SCE 23B-04 Incorporation of Extreme Weather Events into Planning Models; and ACI SCE-25U-02 Cross-Utility Collaboration on Best Practices for Inclusion of Climate Change Forecasts in Consequence Modeling, Inclusion of Community Vulnerability in Consequence Modeling, and Utility Vegetation Management for Wildfire Safety for additional detail). Note: SCE has developed a schematic depicting Wildfire Risk modeling for

FireSight 8 using the elements from the CPUC Risk Informed Decision-Making Proceeding (Ph III), combined with OEIS prescribed risk components in the form of a risk bowtie (See Appendix B: Supporting Documentation for Risk Methodology and Assessment.5).

Substantive modifications include: a) the expansion of simulation domain to provide coverage to assets outside of the current CPUC designated High Fire Threat District (HFTD); b) an improved FWD selection methodology to better reflect fire weather conditions in specific regions of SCE's service territory; and c) an ability to provide quasi-probabilistic consequence distributions at various simulation truncation points (e.g. eight (8) and twenty-four (24) hours) for comparison.

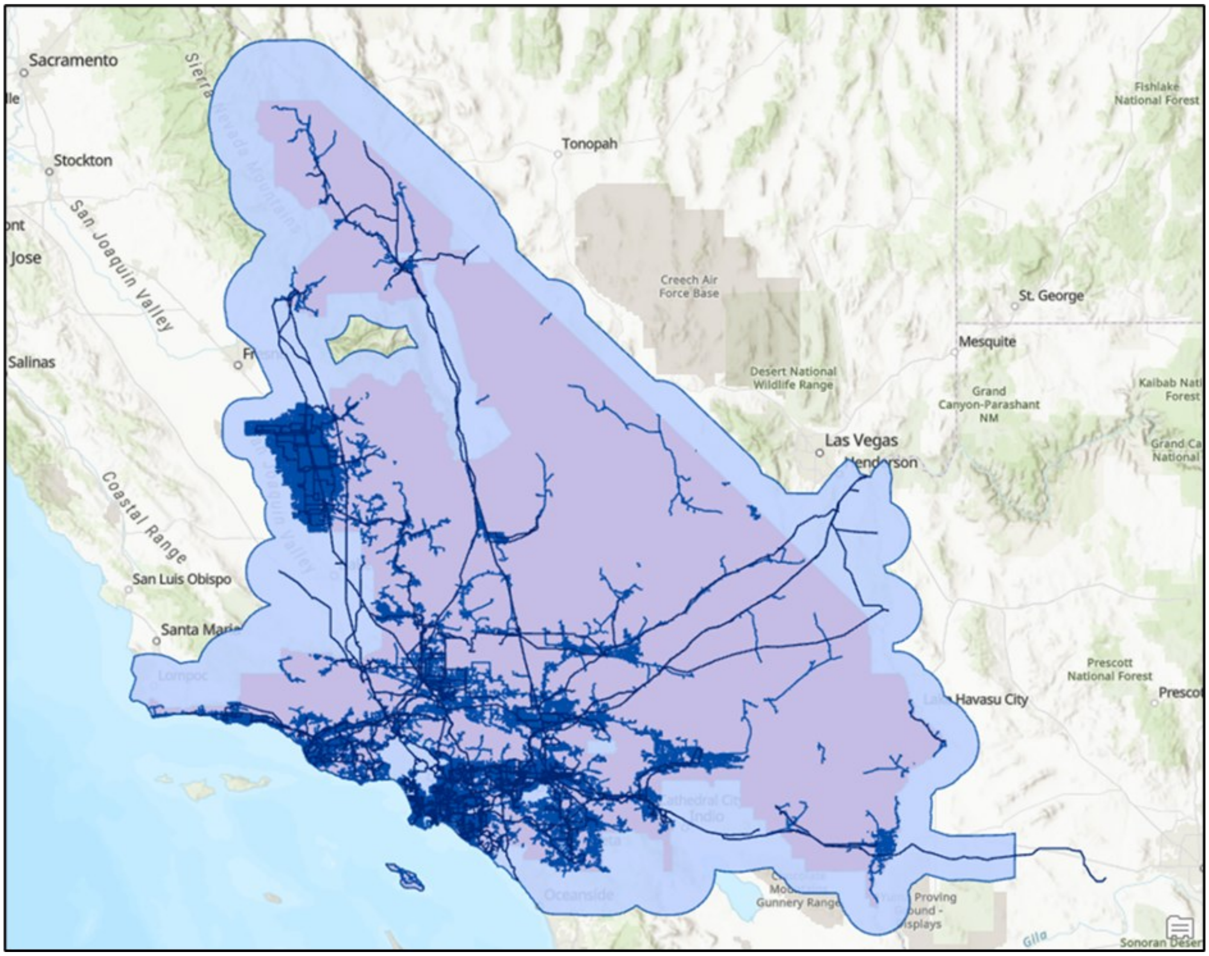
Minor modifications include: a) updated fuel models; b) alignment with Uber H3 hexagon hierarchical spatial indexing standard; c) location-based building loss factors; and, d) local adjustment of fuels in proximity to the Wildland Urban Interface (WUI).

5.2.2.2.2.1 Expansion of Simulation Domain

FireSight 8 includes an expanded wildfire simulation domain that expands SCE's simulation by roughly 32,000 square miles, to approximately 81,000 square miles. Previous versions of SCE's wildfire consequence model only included simulations both within and adjacent to (20-mile buffer) SCE's current approved CPUC designated High Fire Threat District (HFTD). FireSight 8 includes coverage for all of SCE's service territory, as well as the vast majority of assets[49] which traverse the neighboring states of Nevada and Arizona (see Figure SCE 5-28 below). It includes locations in remote parts of SCE's service territory that are not currently part of CPUC HFTD or SCE HFRA and have been under-analyzed based on publicly available models, such as the White Mountains on the California side of the California border. Expanding the simulation domain allows SCE to gather information for all SCE assets in both HFTD and Non-HFTD locations to ensure they are prioritized for operational and maintenance activities in a consistent manner.

49 There is a small portion of Arizona in which SCE does not maintain weather stations in the Sonoran Desert of Western Arizona near the Palo Verde busbar. See Figure SCE 5-28 for additional information.

Figure SCE 5-28: Spatial Extent of SCE FireSight 8 Model



5.2.2.2.2.2 Updated Fire Weather Day Methodology

Concurrent with the expansion of SCE's wildfire simulation domain, SCE has modified its FWD selection process for several reasons: a) to better represent critical fire weather for specific parts of its service territory; b) to align with a similar architecture being tested for its operational wildfire risk models (e.g. FPI 2.0); c) to facilitate the integration of Global Climate Models (GCMs) into SCE's wildfire risk models; and d) to allow SCE to demonstrate the results of extremely granular consequence distributions at every simulated ignition point. The last reason is necessary for transitioning to quasi-probabilistic risk models as it will allow SCE to understand both the frequency of specific Fire Behavior Outcomes and associated consequences without losing the fidelity of granular ignition simulations (see SCE response to Appendix D: Areas for Continued Improvement: SCE-25U-01 Calculating Risk Scores Using Maximum Consequence Values; as well as Appendix B: Supporting Documentation for Risk Methodology and Assessmentfor additional details). FBM is also used to make operational decisions and will be used for SCE's FPI 2.0 in the future (please refer to Section 10.1.1 for more information).

Total Weather Days (TWD) – a complete set of fuel moisture, wind, and weather data representing conditions in SCE's historical climatology.

Fire Weather Day (FWD) – a day within a complete set of TWDs in which fuel moisture, wind, and humidity characteristics represent conditions conducive to a wildfire event. These days represent a subset of all days within SCE historical weather and fuels data set.

Fire Climate Zone (FCZ)– a geographic area having similar terrain, fuels, weather, and fire activity. These locations represent a subset of SCE's service territory.

Fire Behavior Matrix (FBM) – a matrix used to select FWD from SCE's historical climatology for a given FCZ. Individual quadrants of the FBM are referred to as Fire Behavior Outcomes. Each FCZ is represented by a single FBM. Each FBM contains 16 individual Fire Behavior Outcomes.

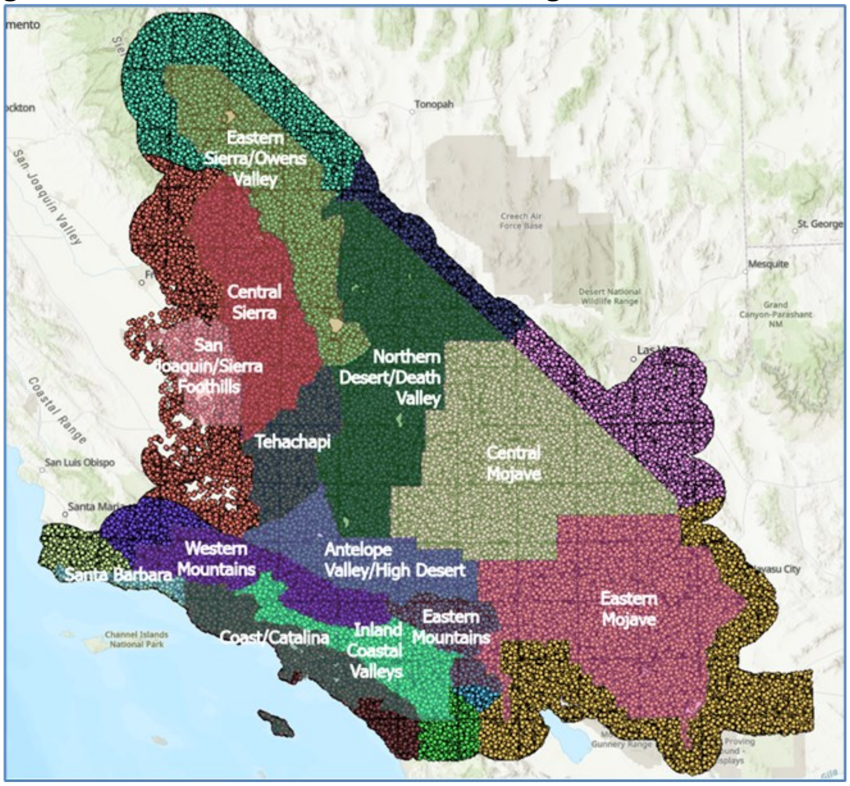
Fire Behavior Outcome (FBO) – a specific quadrant of a FBM. Each FBO represents a specific ranking of fuel dryness and windiness relative to other weather conditions in each FCZ. Quadrants 1D, 2D, 3D, 4D, 2C, 3C, 4C, 3B, 4B, 4A represent days that are conducive to wildfire events in specific FCZ. The ratio of FWD to TWD, as well as the sum of FBO-specific FWD in comparison to TWD, can be used to derive a historical frequency of fire weather conditions. The former can be used to derive a FCZ wide frequency, while the latter can be used to derive a more granular FBO specific frequency. These frequencies can, in turn, be used in conjunction with the corresponding simulated consequences to derive a quasi-probabilistic assessment of the relative risk of individual locations for any duration of simulation (e.g., 8 or 24 hours).

FWDs are one of the most critical inputs into wildfire risk models as these inputs – along with surface fuels – are critical factors in estimating the extent of wildfire consequences. They represent the live and dead fuel moisture, wind (intensity, speed, direction), and other critical weather attributes present at the time of the simulated ignition events. In previous REAX-based versions of SCE's wildfire risk model, weather days were selected to match the days employed during the development of the CPUC HFTD Fire Map process. These REAX-based fire weather days were intended to represent the fire weather present in the entire state of California.

When SCE transitioned to Technosylva-based models (WRRM 5.1 through 7.6) and 41 weather days, SCE added 403 weather days to further represent specific fire weather days within SCE's service territory. This important advancement allowed SCE to understand the nuances of conditions within each portion of its service territory; however, it also lacked the granularity to represent the fire weather conditions within each of the varied regions of its service territory.

In FireSight 8, SCE remedied this issue by selecting FWDs to align with a carefully curated dataset of fire weather conditions germane to each of its Fire Climate Zones (FCZ). FCZs are specific areas of SCE's service territory with similar terrain, fuels, weather, and fire activity. For example, wildfires in certain FCZs are more wind driven, while wildfires in other FCZ are more driven by dry fuel conditions. In this latest version of the model, SCE only used FWD relevant to individual FCZs to run ignition simulations in those FCZ (see Figure SCE 5-29). This is an important advancement, as the consequences resulting from these simulations are better able to represent: 1) the nuances of fires weather conditions in each FCZ, 2) the frequency of FBO, and 3) the distribution of relevant-to-specific ignition points within each geographic area of SCE's service territory. In essence, SCE has transformed a deterministic model into a quasi-probabilistic model without the need for course calibration of stochastic models and the associated systemic uncertainties.

Figure SCE 5-29: Fire Climate Zones and Ignition Point Locations

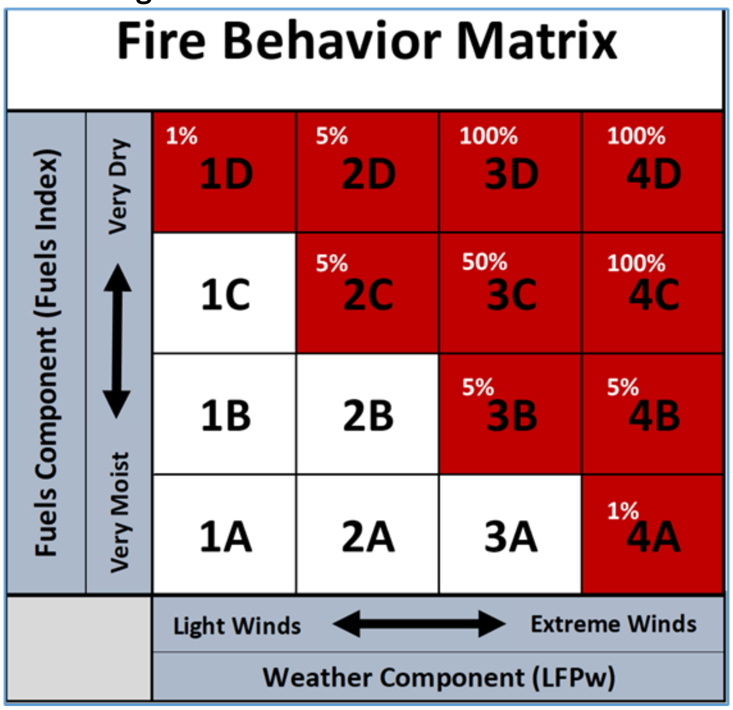


Note: Areas outside of SCE's service territory employ FWDs from adjacent FCZs to represent fire weather conditions in those locations.

SCE used a FBM to select FWD from TWD in a historical climatology area for a given FCZ. FWD are days in which fuel moisture, wind, and weather data represent conditions conducive to a wildfire event, whereas TWD are days that represent the full set of fuel moisture, wind, and weather data for both Fire and non-Fire Weather Days in SCE's historical climatology. By selecting only relevant FWD from a full set of TWD obviates the need to consider Burn Probability (BP). Therefore, for the sake of completeness, SCE assumes a conditional burn probability of "1" within the OEIS WMP guidance. The FBM (Figure SCE 5-30) is generated with the use of weather index data (along the x-axis) and fuels index data (along the y-axis). Each axis contains three break points to create sixteen (4x4) individual quadrants.

Individual quadrants of the FBM are referred to as FBOs. Each FCZ is represented by a single FBM. Each FBM contains 16 individual FBOs. The FBM is generated with the use of Large Fire Potential related to Weather (LFPw) data (the weather component along the x-axis) and the Fuels Index (FI) data (the fuels component along the y-axis). Each component has three break points to create individual quadrants representing specific weather conditions (see Figure SCE 5-29, above). Each FBO represents a specific ranking of fuel dryness and windiness relative to other weather conditions in the FCZ. Quadrants 1D, 2D, 3D, 4D, 2C, 3C, 4C, 3B, 4B, 4A are FBO that represent fire weather conditions. The TWD in SCE's historical climatology can be allocated to each of these FBO to determine a count or frequency of both TWD and the subset of FWD for each FCZ. Figure SCE 5-31 depicts the ratio of FWD to TWD based on the historical frequency of FBO for select FCZ. These frequencies can then, in turn, be used in conjunction with the corresponding simulated consequences to derive a quasi-probabilistic assessment of the relative risk of individual locations for any duration of simulation (e.g., 8 or 24 hours). SCE is in the process of using this FWD based architecture to further assess the potential increase in frequency in FWD for each of these FCZ due to forward looking climate change, as part of FireSight 8 (Climate) (see Section 3.7 for additional information). In FireSight 8, SCE selected a total of 1,713 unique weather days out of 15,342 TWDs in its historical data set.[50] Note these days are not mutually exclusive, and some weather days may be relevant across multiple FCZs.[51]

Figure SCE 5-30: Fire Behavior Matrix



Notes:

Box 1A (bottom, left) represents wet (least dry) and benign (not windy)

Box 1D, (top, left) represents dry and benign (not windy)

Box 4A (bottom, right) represents wet (least dry) and windy;

Box 4D (top, right) represents both dry and windy;

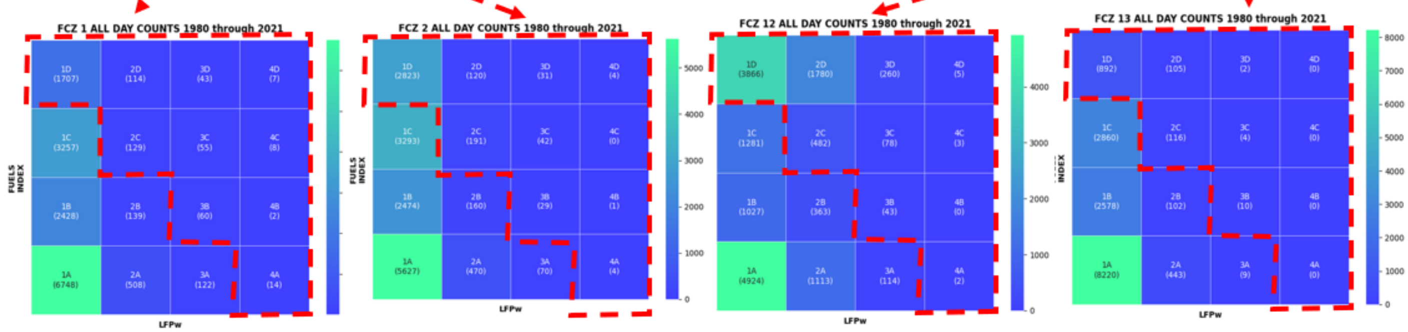
Percentage values represent the percentage of days selected for simulation.

50 1980 – 2021 SCE Weather Research and Forecasting model (WRF).

51 SCE has developed a schematic depicting Wildfire Risk modeling for FireSight 8 using the elements from the CPUC Risk Informed Decision-Making Proceeding (Ph III), combined with OEIS prescribed risk components in the form of a risk bowtie (See Appendix B: Supporting Documentation for Risk Methodology and Assessment).

Figure SCE 5-31: Ratio of Fire Weather Days to Total Weather Days for Select Fire Climate Zones

	FCZ 1 Coast/ Catalina	FCZ 2 Inland Coastal Valleys	FCZ 3 Western Mountains	FCZ 4 Eastern Mountains	FCZ 5 Eastern Mojave	FCZ 6 Antalope Valley/ High Desert	FCZ 7 Central Mojave	FCZ 8 Northern Desert/ Death Valley	FCZ 9 Eastern Siera/ Owens Valley	FCZ 10 Central Sierras	FCZ 11 San Joaquin/ Sierra Foothills	FCZ 12 Tehachapi	FCZ 13 Santa Barbara
FWD Selected	122	105	97	191	419	115	422	412	236	29	66	464	28
TWD	15342	15342	15342	15342	15342	15342	15342	15342	15342	15342	15342	15342	15342
FWD/TWD Ratio	*0.8%*	*0.7%*	*0.6%*	*1.2%*	*2.7%*	*0.7%*	*2.8%*	*2.7%*	*1.5%*	*0.2%*	*0.4%*	*3.0%*	*0.2%*



Transition to Quasi-Probabilistic Model

The new FWD selection process allows SCE to transition to a quasi-probabilistic model without losing spatial granularity. We believe this methodology is superior to existing probabilistic models which tend to have insufficient granularity to guide the deployment of individual mitigations.[52]

In its 2025 WMP Update in response to ACI SCE-23-02 "Calculating Risk Scores Using Maximum Consequence Values in its 2025 WMP Update" SCE stated:

"In 2026-2028 WMP filing, SCE intends to provide additional information for its wildfire simulations so that parties can better understand the historical return interval (e.g., quasi-probabilistic) of the weather scenarios used in its wildfire simulations. This return interval information can be used in conjunction with consequence values to better understand the relative risk of catastrophic wildfires in discrete locations. We will continue to note the potential limitations and weaknesses of using this approach—namely, that even the use of the maximum consequence values may underrepresent the risk at certain locations given that the risk is likely to increase over time."

Through the new FWD selection process, SCE can provide the historical frequency of various FBO by FCZ (see Figure SCE 5-31 in the preceding section). These historical frequencies differ by the type of fire weather in each location. Some parts of SCE's service territory are subject to more wind-driven wildfire events, whereas other portions of the service territory are subject to more fuel-driven wildfire events. With this information, SCE can correlate the frequency of each FBO to the resulting consequence values for these simulation events at each individual ignition point. The result is both a full distribution of individual consequences (in natural units) across all weather scenarios, and, if needed, an understanding of the frequency of fire behavior for specific

52 U.S. Forest Service, Wildfire Risk to Communities Burn Probability. See https://data-usfs.hub.arcgis.com/datasets/d93720867d1a4aa69f4a15dbf3ddeaea/explore?location=34.251879%2C-118.066303%2C9.84.

portions of the consequence curve (see Figure SCE 5-33 and Figure SCE 5-34 below) at various simulation truncation points (e.g., eight (8) and twenty-four (24) hours).

Note the “max” consequence for these truncated simulations are different. The max natural unit consequence is almost 4,500 acres for the 8-hour simulation, and the mean consequence is around 1,500 acres; whereas the max natural unit consequence is nearly 45,000 acres for a 24-hour simulation (almost 10 times the value), and the mean consequence value is around 10,000 acres.

As stated in past WMPs, the further out in time the simulation progresses, the more uncertain the results. Other factors, such as changing wind and weather conditions, as well as various levels and effectiveness of suppression, increase the uncertainty of simulation events beyond the 8-hour period. Uncertainty in the accuracy of the modeling increases as simulation duration increases (See Figure SCE 5-32). This holds true for both probabilistic and deterministic wildfire risk models. However, longer simulations may capture more extreme events where suppression resources are limited. Therefore, SCE continues to recommend the use of maximum consequence *based on truncated 8- or 24-hours simulation periods* given that these values represent actual historical fire weather conditions.[53] We also note that for while vast majority of wildfire events, the public safety consequences occur within these first burning periods. Catastrophic wildfires are infrequent yet have severe consequences that SCE must consider when developing and deploying mitigation measures. SCE’s methodology of calculating risk scores using maximum consequence values based on a truncated 8- or 24- hour simulation period values is consistent with the language of Senate Bill (SB) 901. Additionally, SCE’s methodology is not materially different than those employed by other California Investor-Owned Utilities (IOUS). See additional information in Appendix D: Areas for Continued Improvement SCE ACI SCE-25U-01 Calculating Risk Scores Using Maximum Consequence Values.

While the distribution of consequence values generally follows a power law distribution for simulations from this ignition point location, not all simulations follow this same pattern. Some simulations results are flat or steeply drop off as they reach slower fuel types (e.g., urban) or non-burnable fuel types (e.g., water, bare ground/rock). Other simulations increase sharply, then exponentially, as they transition from slower-burning, denser fuel to quicker-burning, lighter fuel type. Based on guidance in the RDF proceeding, SCE may submit a whitepaper further describing these results ahead of its next RAMP application.[54]

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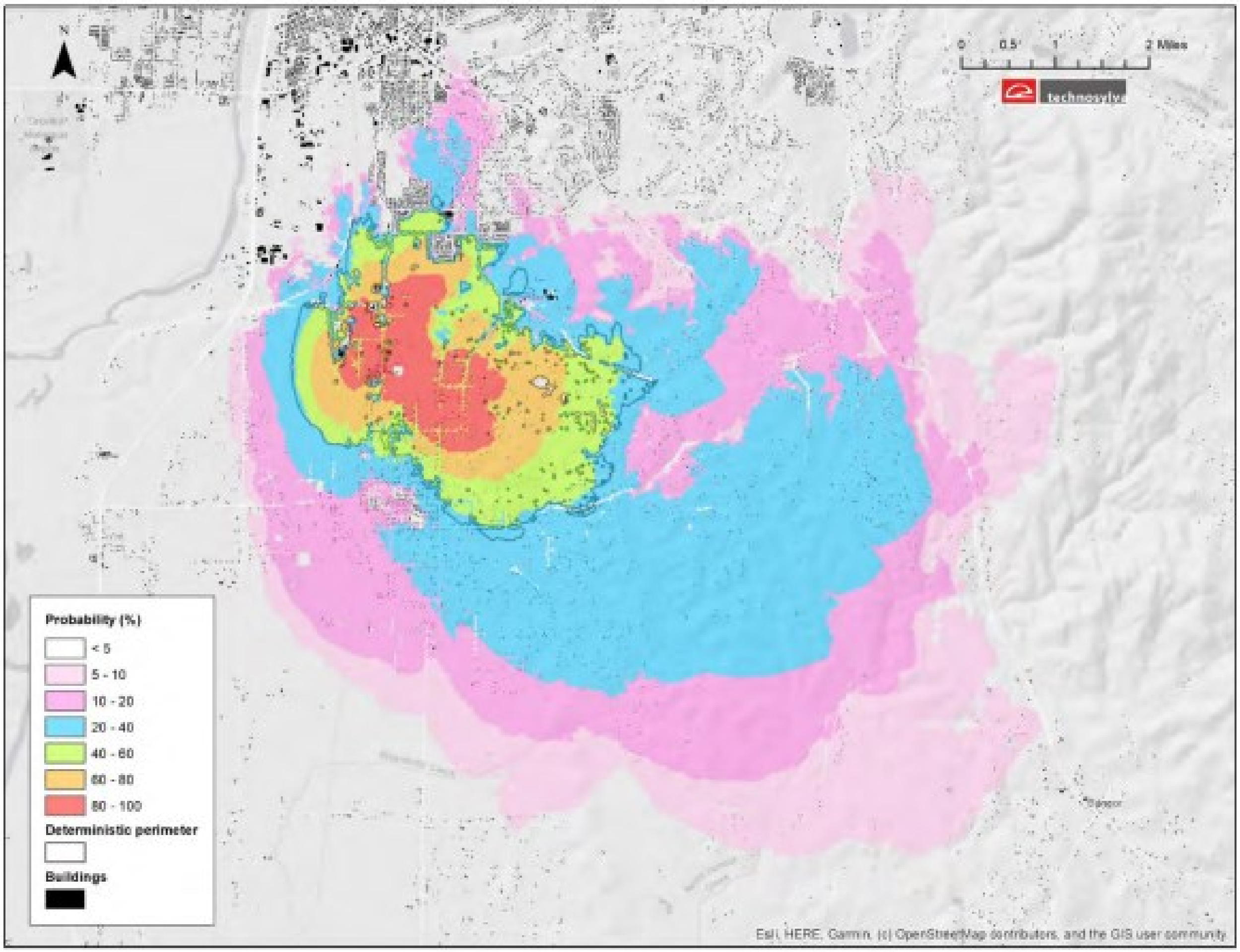
53 See depiction of how uncertainty increases over time for wildfire simulation, *California Public Utilities Commission 2019 PSPS Event –Wildfire Analysis Report – SCE*, specifically ppg. 9-10 https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/safety-and-enforcement-division/documents/technosylva-report-on-sce-psps-events-2019.pdf

54 See D.24-05-064, Conclusions of Law, RDF Phase III.
p.21. “The Commission should identify a power law distribution model as a best practice for wildfire tail risk modeling with regard to the optional modeling of tail risk, in addition to expected value, in Row 24 of the RDF”.
p.22. “If an IOU elects to model wildfire tail risk pursuant to Row 24 using the truncated power law approach, the Commission should require the utility to submit both its expected value model and its tail risk model with its RAMP filing.”
p.23. “If an IOU elects to use a method other than truncated power law to model wildfire tail risk pursuant to Row 24, in addition to presenting the required expected value, the Commission should require the IOU to provide to SPD and serve to the service list of R.20-07-013 a White Paper submission justifying its approach, and related workpapers, no later than 45 days before

Figure SCE 5-32: CPUC 2019 PSPS Event – SCE Wildfire Analysis Report



Note: Uncertainty in the accuracy of the modeling increases as simulation duration increases

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the IOU's first pre-RAMP workshop and to also attach the White Paper and related workpapers to their RAMP filing, clearly indicating any modifications to the previously served White Paper."

Figure SCE 5-33: Full Distribution of Natural Unit Consequences (Acres Burned) for a Simulation Truncated Period of 8 Hours55

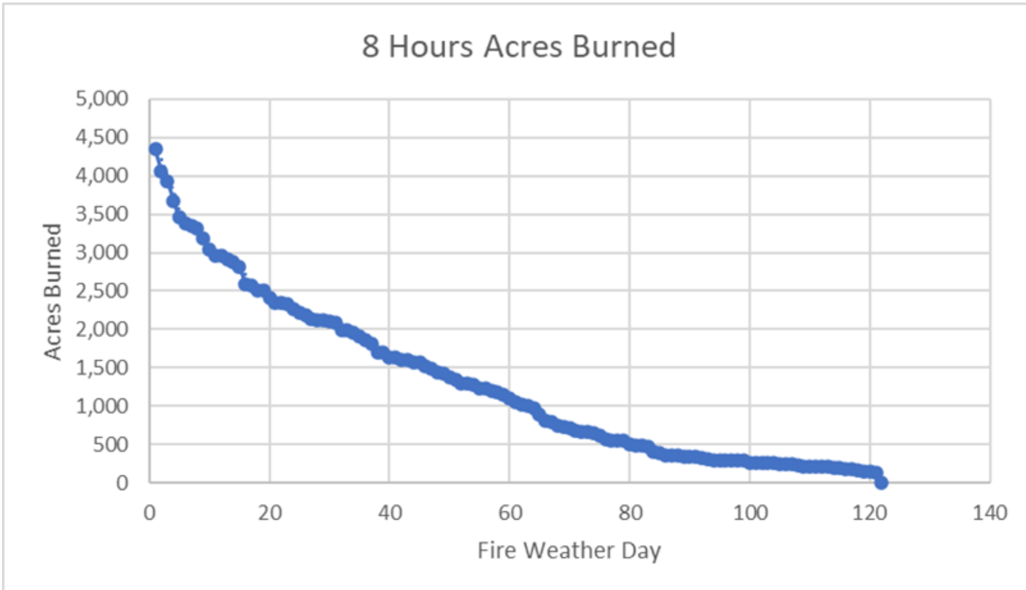
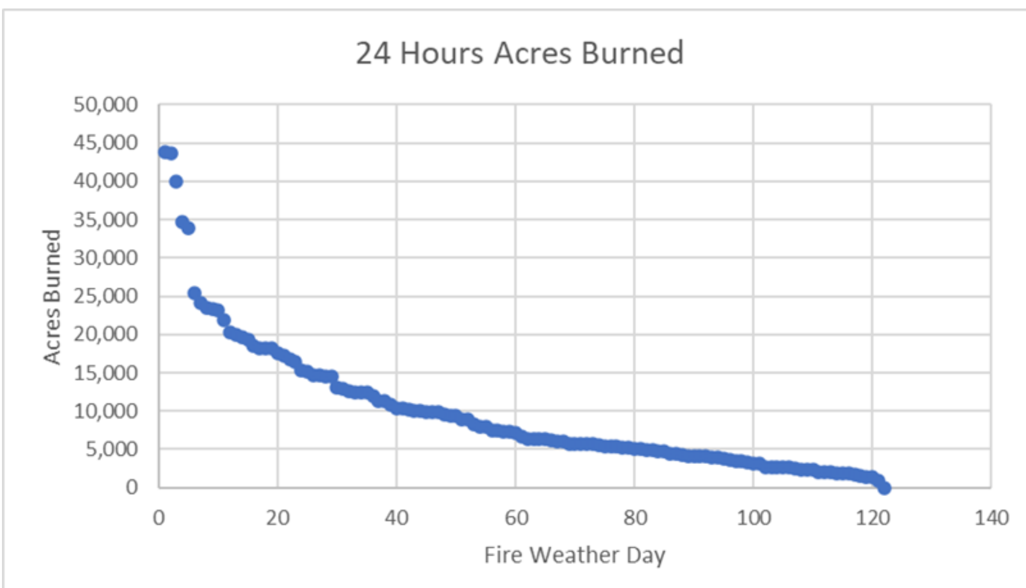


Figure SCE 5-34: Full Distribution of Natural Unit Consequences (Acres Burned) for a Simulation Truncated Period of 24 Hours[56]



55 For reference: Ignition point number 22364473; Latitude: 34.424484; Longitude: -119.05461.

56 For reference: Ignition point number 22364473; Latitude: 34.424484; Longitude: -119.05461.

5.2.2.2.2.3 Updated Fuel Models

Along with the expansion of its simulation domain, SCE expanded its fuel models to include fuel inputs for these new locations:

- A. Updated fuel models for areas with major fire scars. These locations were progressed to represent fuels that will likely be present in those areas in the year 2035.[57] See Figure SCE 5-35.

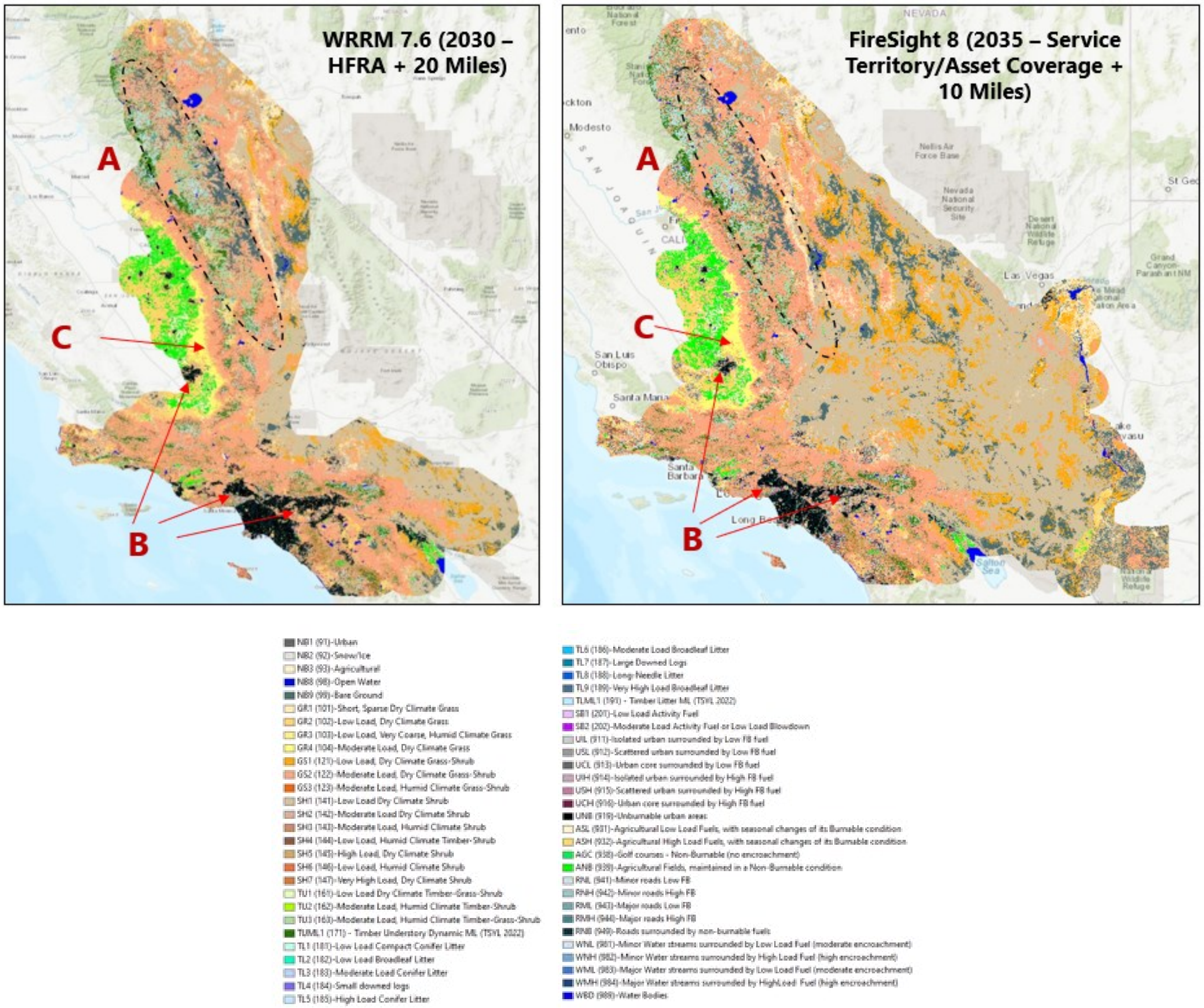
- B. SCE also created a new algorithm to better represent fuels in Wildland Urban Interface (WUI) areas. Fuels in these locations are often misrepresented due to lags between the date the fuels models were created and when buildings, particularly new neighborhoods, are developed. See Figure SCE 5-35.

- C. SCE adjusted fuels in certain locations to better represent grass-based fuels, primarily in FCZ 11 along the foothills of the San Joaquin Valley. See Figure SCE 5-35.

- D. SCE also implemented a new location-based Building Loss Factor (BLF) to represent the ratio of Buildings Damaged (BDam) to Buildings Destroyed (BDes). These BLF were calibrated based on data from CAL FIRE Damage Inspection Data.[58] See Figure SCE 5-38.

57 WRRM 7.6 and prior progressed fuels to represent a likely 2030 year.
58 CAL FIRE Damage Inspection Data https://data.ca.gov/dataset/cal-fire-damage-inspection-dins-data.

Figure SCE 5-35: FireSight 8 Fuel Layer Domain (Right) Compared to WRRM 7.6 (Left)

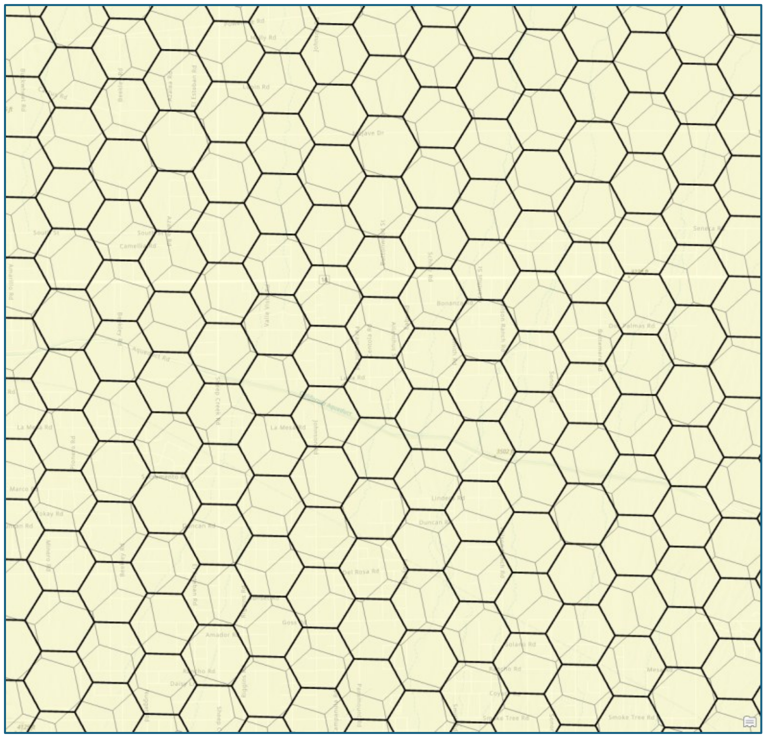


5.2.2.2.2.4 Uber H3 Hexagon Hierarchical Spatial Index

SCE was the first utility to adopt the hexagon spatial architecture to represent a common geography across metrics.[59] (see Section 5.2.1.2.1.1 regarding SCE's SRA methodology). Hexagons are a common geography that are useful in aggregating different types of data (points, buildings, assets), independent of political boundaries. The centroid of each polygon is equidistant from each adjacent polygon. Given the growing popularity of this industry standard, SCE has aligned its existing risk models with the Uber H3 hexagon hierarchical spatial indexing standard. Additionally, in the FireSight 8 model, SCE uses the Uber H3 standard for adjustments to WUI fuels and in its exploration of Building Loss Factor (BLF) metrics.

59 It is the foundation of our Severe Risk Area (SRA) methodology.

Figure SCE 5-36: Comparison of Uber H3 Hexagons with Prior Hexagon Lattice



Uber H3 hexagons are represented by thick black lines. SCE had formerly used the hexagon lattice represented by light gray lines.

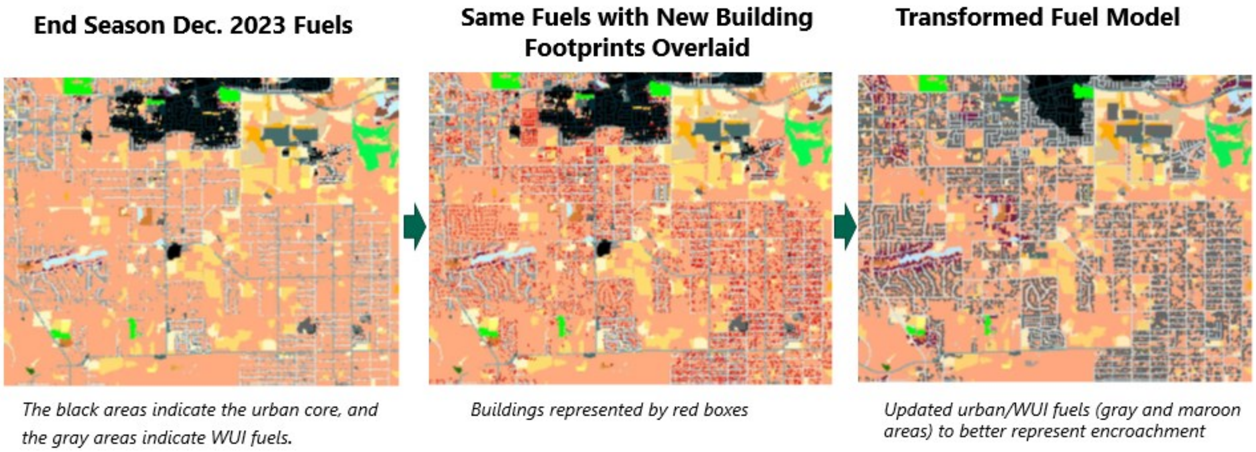
5.2.2.2.2.5 WUI Fuel Adjustments

In FireSight 8, SCE used the Uber H3 grid to make local adjustment of fuels in proximity to the WUI. Fuels in these locations are often misrepresented due to lags between the date the fuels models were created and when buildings, particularly new neighborhoods, are developed. For example, fuel maps are generally created through satellite detection methods that tend to focus on more remote parts of the service territory, as well as areas which have recently been damaged by natural hazards (e.g., wildfires, floods, landslides, etc.).

In areas of rapid construction, particularly along the WUI, it may be several years before these locations are remapped. Given that wildfire ignition simulations are extremely sensitive to the underlying fuels, this inconsistency required SCE SMEs to constantly review and revise risk models in areas subject to rapidly evolving Land Use Land Cover (LULC), such as the Inland Empire.

SCE developed a new method to update fuel models by overlaying building footprints onto these fuels, transforming the fuel model into custom Technosylva-based fuels. The new method improves the representation of the spread of surface fires across urbanized terrain. Based on these transformations, SCE's results indicate a slight decrease in the number of total buildings potentially impacted in these locations. See Figure SCE 5-37 for an illustrative example of the transformation process.

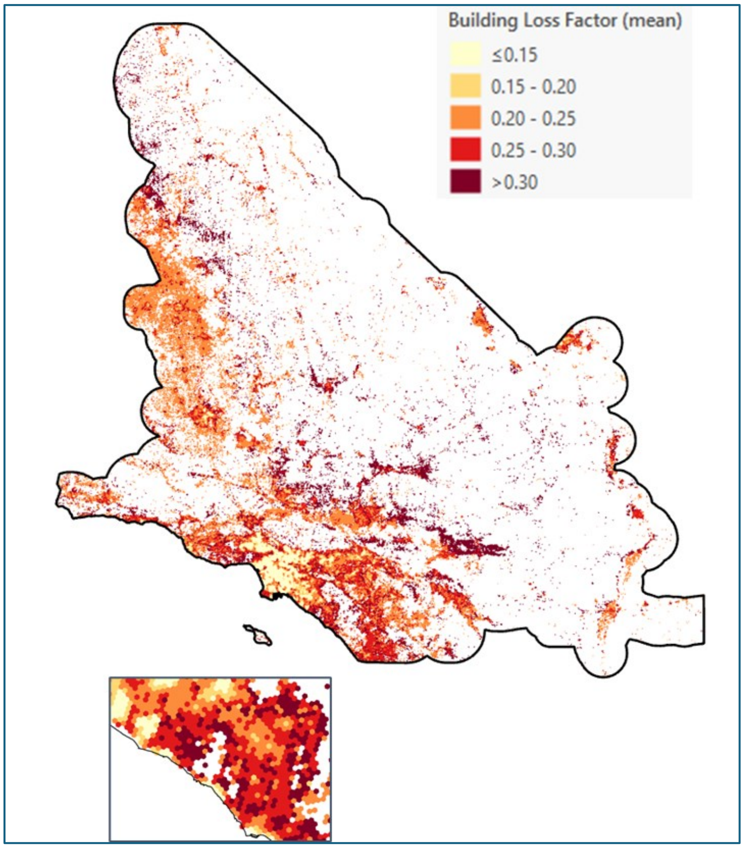
Figure SCE 5-37: Illustrative Example of WUI Fuel Transformation



5.2.2.2.2.6 Building Loss Factor

In FireSight 8, SCE has received new Building Loss Factor (BLF) information. SCE is exploring ways to utilize this BLF to better represent the ratio of Building Damaged (BDam) to Buildings Destroyed (BDes) within a given fire perimeter. As fireshed simulations progress across building footprints, the BLF generates an estimate to distinguish between buildings that likely survive the fire, but are damaged versus those buildings which are completely destroyed. These BLFs were calibrated based on data from CAL FIRE Damage Inspection (DINs) data. Previous versions of SCE's Wildfire Risk Model (e.g., WRRM 7.6) did not distinguish between these two metrics. We expect the use of these factors will allow SCE to more accurately represent consequence metrics for building impacts.

Figure SCE 5-38: (D) Building Loss Factor in SCE's Service Territory



5.2.2.2.2.7 Overall MARS Risk Score

Safety Consequences: SCE defines serious injuries and fatalities as those associated with both members of the public and firefighters injured during a wildfire event based on known reported information. To estimate Safety Consequence associated with individual wildfire simulations, SCE uses a ratio of 256 structures impacted to one fatality, and a ratio of 107 structures impacted to one serious injury. These ratios are based on recent historical wildfires in SCE's service territory. These safety consequences are then combined into a Safety Index in which one serious injury is equal in value to one quarter fatality. The resulting values are enhanced by a circuit specific AFN/NRCI Multiplier to represent location specific Wildfire Vulnerability.

Figure SCE 5-39: SCE Safety Consequences Calculation

$$\text{Safety Index} = 1 \text{ x Fatalities } \times \tfrac{1}{4} \text{ Serious Injuries x Wildfire Vulnerability}$$

Reliability Consequences: SCE assumes an eight-hour service interruption for each customer account on the circuit from which that ignition occurred. SCE understands these numbers may be a conservative estimate given that fire sheds may impact multiple circuits during an actual wildfire event. These impacts are represented by the number of customer minutes of service interruptions (CMI).

Figure SCE 5-40: SCE Reliability Consequences Calculation

$$\text{Reliability} = \#\ \text{Customers} \times (8\ \text{hours} \times 60\ \text{minutes})$$

Financial Consequences: SCE uses average cost information representing costs associated with damage to physical structures, as well as firefighting suppression costs and land restoration costs for each individual wildfire simulation. To model socio-economic equity across SCE's service territory, SCE uses a system-wide average estimated cost of $1,000,000 per building impacted. [60] SCE understands these numbers may be a conservative estimate given that insured losses may exceed actual structure values for each wildfire event. SCE also uses a per-acre firefighting suppression cost figure of $876; and a per-acres land restoration cost of $1,460.[61]

Figure SCE 5-41: SCE Financial Consequences Calculation

$$\text{Financial} = (\#\ \text{of Buildings Destroyed}) \times (\$1{,}000{,}000) + (\#\ \text{of Acres}) \times (\$876) + (\#\ \text{of Acres}) \times (\$1{,}460)$$

In Table 5-3, SCE summarizes the associated attributes, units, weights, ranges, and scaling functions to convert natural units of consequence (e.g., CMI, dollars, safety) into a unit-less risk score. These components were based on the principles set forth in the S-MAP Settlement and presented in SCE's 2022 RAMP filing.

SCE notes that it is not required to implement a Cost-Benefit Approach until its 2026 RAMP filing.[62] SCE also notes that while utilities must use Cost-Benefit ratios to rank mitigations, the Commission has recognized that cost-benefit ratios should not be the only factor used in activity selection and prioritization.[63] In order to transform MARS units into a Cost-Benefit Ratio, SCE employed the following method, which was also used in its 2025 General Rate Case.

60 Estimated average structure value is based on a standard average value of structures in SCE's service territory. In the 2026-2028 WMP update, SCE aligned with SDG&E and PG&E for a statewide standard structure value.

61 Suppression costs are based on a five-year average of California's reported wildfire suppression costs from 2016-2020.

62 Decision 22-12-027 Conclusion of Law 6. "The Commission should require the IOUs to implement the refined RDF including the Cost-Benefit Approach in each utility's next respective GRC cycle, beginning with PG&E's 2024 RAMP application."

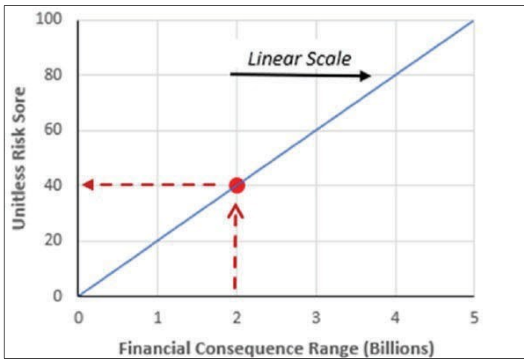
63 Decision 22-12-027 Conclusion of Law 7. "While utilities must use Cost-Benefit Ratios to rank mitigations in their GRCs, mitigation Cost-Benefit Ratio rankings need not be the only consideration in the utility's selection of Mitigations, as explained in Row No. 26 of the RDF contained in Appendix A of this decision."

Table SCE 5-03: MARS Conversion Table

Attribute	Units	Weight	Range	Scaling Factor
Safety	Index	50%	0 - 100	Linear
Reliability	Customer Minutes of Interruption (CMI)	25%	0 - 2 billion	Linear
Financial	Dollars	25%	0 - 5 billion	Linear

Figure SCE 5-42 provides a step-by-step illustrative example using the weights, ranges, and scaling functions to transform consequences (in this example Financial) into a unitless risk score. The same methodology would be used for the safety and reliability consequences.

Figure SCE 5-42: Illustrative Example of MARS Conversion Steps for Financial Consequences



Step	Action	Value
1	Identify Consequence Value	$2 Billion
2	Determine Scaled Score	40
3	Identify Attribute Weight [Financial]	25%
4	Apply Weight to Scaled Score	10 = 25% * 40
5	**Financial Risk Score (MARS)**	**10**

5.2.2.2.3 Other Consequence Risk Components

FRC5: Wildfire Hazard Intensity

SCE's wildfire risk model (i.e., FireSight 8) only considers FWDs in which fuel and/or wind conditions are present to produce a wildfire event.

See Section 5.2.2.2.2.2, as well as Appendix B: Supporting Documentation for Risk Methodology and Assessment Fire Weather Day (FWD) selection methodology for additional information; and SCE response to Appendix D: Areas for Continued Improvement: SCE-25U-01 Calculating Risk Scores Using Maximum Consequence Values for additional details regarding this approach.

FRC6: Wildfire Exposure Potential

SCE does not have a separate risk component for Wildfire Exposure Potential, as SCE considers the exposure potential of all locations within its service territory (FireSight 8). This includes the CPUC designated portions of its service territory, which are subject to extreme or elevated wildfire exposure potential.

FRC7: Wildfire Vulnerability

SCE has developed a multiplier to represent the vulnerability of customers to a wildfire or PSPS event. The purpose of this multiplier is to amplify the safety index based on the relative ranking of those circuits compared to other circuits in HFRA based on the total AFN and NRCI customers on those circuits.

AFN customers include those customers which are subject one or more of the following criteria: Critical Care, disabled, Medical Baseline, Low Income, limited English, pregnant, children. NRCI customers include those customers in the Healthcare and Public Health, Water and Wastewater Systems, Emergency Services, Communication, Transportation, Government Facilities, or Energy sectors.

An AFN multiplier value of “2” represents the highest AFN score compared to other circuits in the HFRA; an AFN multiplier value of “1” represents a circuit with an AFN score of zero. Similarly, a circuit with an NRCI multiplier value of “2” represents the highest NRCI score compared to all of the other circuits in HFRA; an NRCI score of “1” represents a circuit with a NRCI score of zero.

In the case of Wildfire Vulnerability, this multiplier represents the relative level of support that an individual or entity would need in the case of a wildfire event.

Figure SCE 5-43: AFN Multiplier Calculation

$$AFNCircuitMultiplier = 1 + \frac{AFN\ ScoreCircuit}{AFN\ Score\ Max}$$

Figure SCE 5-44: NRCI Multiplier Calculation

$$NRCI_{CircuitMultiplier} = 1 + \frac{NRCI\ ScoreCircuit}{NRCI\ Score_{\ Max}}$$

Figure SCE 5-45: Wildfire Vulnerability Calculation

$$Wildfire\ Vulnerability\ Circuit = AFN\ CircuitMultiplier \times NRCI\ CircuitMultiplier$$

Wildfire vulnerability in IWMS is incorporated based on the consideration of locational risk factors including known Communities of Elevated Fire Concern, locations with high fire frequency and population egress, as well as locations in which an ignition could cause a wildfire which could spread to and trap populations in identified egress locations (i.e., “Burn in Buffer”). Please see the description of the IWMS Risk Framework in Section 5.2.1.2.

IRC6: PSPS Consequence

SCE estimates PSPS Consequences associated with a proactive de-energization event by using the number of customers impacted along with the potential frequency and duration of those events to estimate potential safety, reliability, and financial impacts.

Safety Consequences: SCE multiplies the total customers in scope by three to estimate the total population impacted. The resulting total population impacted is then multiplied by a safety conversion factor, based on epidemiological data from several widespread outage events to estimate the number of fatalities and serious injuries. To estimate Safety Consequence associated with individual PSPS simulations, SCE uses a ratio of 0.00000002870 fatalities per customer de-energized, and a ratio of 0.00000012671 serious injuries per customer de-energized. SCE has updated this safety consequence conversion factor in the 2026-2028 WMP to include a wider range of outage events.[64] These safety consequences are combined into a Safety Index in which one serious injury is equal in value to one quarter fatality. SCE adjusts the Safety Index by the applicable PSPS Vulnerability multiplier for the circuit in scope.

Figure SCE 5-46: PSPS Safety Index Calculation

Safety Index = (Population x Safety Conversion Factor: Fatalities) + ¼ (Population x Safety Conversion Factor: Serious Injuries) x PSPS Vulnerability

Reliability Consequences: SCE assumes an 8-hour service interruption for each customer account on the circuit in scope for that event. SCE understands these numbers may be a conservative estimate given that SCE attempts to minimize the number of customers in scope for a given PSPS event. These impacts represent the number of customer minutes of service interruptions (CMI).

Figure SCE 5-47: PSPS Reliability Consequences Calculation

$$\text{Reliability} = \#\ \text{Customers} \times (8\ \text{hours} \times 60\ \text{minutes})$$

Financial Consequences: SCE uses the number of customers to estimate the potential financial impact. SCE uses $250 per customer service account, per de-energization event, to approximate potential financial losses, recognizing that some customers may experience no financial impact, while other customer losses may exceed $250.[65] This estimate has been updated to reflect the per diem rate for food and lodging in the Los Angeles area based on data from the U.S. General Services Administration.[66]

64 Safety Conversion Factor: Fatalities - Calculated based on fatality data from 2003 NE Blackout, 2011 SW Blackout, 2019 PSPS Events, 2021 Texas Storm, 2012 Hurricane Sandy, 2017 Hurricane Irma, 2012 Derecho windstorm events; 0.00000002870 fatalities per customer de-energized.
Safety Conversion Factors: Serious Injuries - Calculated based on hospitalization/injury/safety concern data from 2019 PSPS events, 2003-06 NE Blackouts, 2011 SW Blackout, 2017 Hurricane Irma; 0.00000012671 serious injuries per customers de-energized.

65 This is not an acknowledgment that any given customer has or will incur losses in this amount, and SCE reserves the right to argue otherwise in litigation and other claim resolution contexts, as well as in CPUC regulatory proceedings.

66 U.S. General Services Administration GSA per diem

Figure SCE 5-48: PSPS Financial Consequences Calculation

$$\text{Financial} = \#\ \text{Customers} \times \$250 \text{ per event}$$

Overall MARS Risk Score

SCE uses the same weights, ranges, scaling functions for PSPS as described above in the explanation of Wildfire Consequence.

FRC8: PSPS Exposure Potential

Please see Section 5.2.1.5 for how SCE considers this risk component.

FRC9: PSPS Vulnerability

Please see the discussion above (Section 5.2.2.2.3) regarding how Wildfire vulnerability (FRC7) is determined under the MARS Framework. SCE uses the same approach for PSPS vulnerability.

IRC9: PEDS Outage Consequence

SCE estimates PEDS Outage Consequences by quantifying the increased impact to customers with a potential increase in CMI when Fast Curve is enabled. The equation for potential safety, reliability, and financial impacts are the same as PSPS Consequences. See IRC6 for more details.

Two key elements from the PEDS Outage Consequence are increased number of impacted customers and increased outage duration when Fast Curve is enabled. The total population impacted is estimated by considering the available protection schema and outage scenarios. Fast Curve outages could impact the whole circuit or downstream of a Fast Curve-enabled recloser, which influences the number of customers impacted and the time needed to patrol lines before power can be restored.

FRC10: PEDS Outage Exposure Potential

Please see Section 5.2.1.5 for how SCE considers this risk component.

FRC11: PEDS Outage Vulnerability

Please see the discussion above (Section 5.2.2.2.3) regarding how Wildfire vulnerability (FRC7) is determined under the MARS Framework. SCE uses the same approach for PEDS vulnerability.

5.2.2.3 Risk

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

- *Overall utility risk*
- *Wildfire risk*
- *Outage program risk*
- *PSPS risk*
- *PEDS outage reliability risk*

R1: Overall Utility Risk

Overall Utility Risk is calculated as the sum of wildfire and outage program (PSPS and PEDS outage) risk.

Figure SCE 5-49: Overall Utility Risk Calculation

$$Overall\ Utility\ Risk = Wildfire\ Risk + Outage\ Program\ Risk$$

R2: Wildfire Risk

Wildfire Risk is calculated as the product of the sum of all Ignition Likelihood components and Wildfire Consequence.

Figure SCE 5-50: Wildfire Risk Calculation

$$Wildfire\ Risk = \ Ignition\ Likelihood\ X\ Wildfire\ Consequence$$

R3: Outage Program Risk

Outage Program Risk is calculated as the sum of PSPS risk and PEDS risk.

Figure SCE 5-51: Outage Program Risk Calculation

$$Outage\ Program\ Risk = PSPS\ Risk + PEDS\ Risk$$

IRC4: PSPS Risk

PSPS risk is calculated as the product of PSPS Likelihood (synonymous with Probability of De-energization (POD)) and PSPS Consequence.

Figure SCE 5-52: PSPS Risk Calculation

$$PSPS\ Risk\ =\ PSPS\ Likelihood\ x\ PSPS\ Consequence$$

IRC7: PEDS Outage Risk

PEDS risk is calculated as the product of PEDS Likelihood and PEDS Consequence.

Figure SCE 5-53: PEDS Risk Calculation

$$PEDS\ Risk\ =\ PEDS\ Likelihood\ x\ PEDS\ Consequence$$

5.2.3 Key Assumptions and Limitations

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

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

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

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

- ***Proxies for estimating impact on customers and communities*** *in the service territory.*

- ***Extent, distribution, and characteristics of vulnerable populations*** *in the service territory.*

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

Key Modeling Assumptions

In addition to the attributes listed above, SCE provides its key modeling assumptions in Table 5-1 where applicable. SCE uses its own historical data, research, and studies relevant to wildfire risk assessment as well as those required in other applicable regulatory forums. Where appropriate, SCE describes the data standards used in its risk models in the description of individual components. See Table 5-1, as well as Appendix B: Supporting Documentation for Risk Methodology and Assessment for additional relevant information.

Data Standards

SCE data standards conform to OEIS and CPUC risk model reporting requirements to the extent they are known and are based on the granularity of available data (e.g., segment or functional location level). Where appropriate, SCE describes the data standards used in its risk models in the description of individual components. See Table 5-1, as well as Appendix B: Supporting Documentation for Risk Methodology and Assessment. Additional Models Supporting Risk Calculation for additional relevant information.

Consistency of Assumptions and Limitations

SCE risk models are consistent with guidance provided by OEIS and CPUC risk modeling requirements to the extent known. These assumptions may change over time as new guidance is provided by OEIS or the CPUC. Where appropriate, SCE describes the data standards used in its risk models in the description of individual components. See Table 5-1, as well as Appendix B: Supporting Documentation for Risk Methodology and Assessment for additional relevant information.

Stability of Assumptions in the Program

SCE risk models are consistent with guidance provided by OEIS and CPUC risk modeling requirements to the extent known. These assumptions may change over time as new guidance is provided by OEIS or the CPUC. Where appropriate, SCE describes the data standards used in its risk models in the description of individual components. See Appendix B: Supporting Documentation for Risk Methodology and Assessment for additional relevant information. To the extent there are significant changes or limitations of the underlying assumptions (e.g., fuels, weather scenarios, drivers, etc.) in its risk models, SCE describes the data standards used in its risk models in the description of individual components. See Table SCE 5-01, as well as Appendix B: Supporting Documentation for Risk Methodology and Assessment for additional relevant information.

Monetization of Attributes

SCE does not have monetized attributes at this time.

Table 5-1: SCE Risk Modeling Assumptions and Limitations

	Assumption	Justification	Limitation	Applicable Models
Adaptation of Weather History	SCE leverages 2009-2023 weather data generated from its weather research and forecasting (WRF)	SCE uses machine learning algorithms to associate applicable weather variables from the WRF model at the time of fault/ignition events.	SCE's WRF has a limited spatial granularity of 2KM x 2KM. These historical weather data may not be reflective of future weather conditions.	POI
	SCE uses historical FWD from SCE's historical climatology, as well as data from the most recent California Climate Assessment, where applicable.	These weather days represent fire weather conditions in each of SCE's FCZs.	To increase accuracy and meet the underlying 30m cell size resolution of the fuels data, 2 KM x 2 KM weather data is interpolated spatially using a bilinear interpolation scheme. These historical data may not be reflective of future fire weather conditions.	Wildfire Consequence
Availability of Suppression Resources	SCE does not account for historical or future fire suppression.	The use of a consistent unsuppressed truncated 8-hour and 24 wildfire simulations. The use of a consistent simulation time allows for readily comparable results across all assets	There is inherent uncertainty in agent-based activities, such as fire suppression resources. The overlapping jurisdiction, availability, and coordination of resourcing decisions as well as the timeliness of those decision-making processes based on the ignition detection time make it challenging to model. SCE also notes that in many cases, fire agencies must respond to multiple concurrent fire events, adding complexity to wildfire suppression decision-making. Calibration of historical fires alone does not reflect these decision-making processes. In lieu of artificially	Wildfire Consequence

	Assumption	Justification	Limitation	Applicable Models
			adjusting consequences based on fire suppression, SCE has chosen not to bias these simulations.	
Height of Wind Driving Fire Spread	Fire simulations require wind speed at midflame to compute surface fire spread and at 20ft to compute crown fire characteristics. To convert the initial 10m wind speeds from WRF to 20ft, we use a wind adjustment factor (WAF) from Andrews (2012).	The model is based on the work of Albini and Baughman (1979) and Baughman and Albini (1980), using some assumptions made by Finney (1998).	The sheltered WAF assumes that the wind speed is approximately constant with height below the top of a uniform forest canopy. Sheltered WAF is based on the fraction of crown space occupied by tree crowns.	Wildfire Consequence
General Equipment Failure Rates	SCE bases its equipment failure rates on its predictive models for Equipment/Facility Failure (EFF) subcomponents using 2015-2023+ equipment failure data for its modeled assets.	SCE uses machine learning algorithms to develop predictive models for equipment failure that are validated and tested for accuracy for inclusion in our probabilistic assessment for risk calculations.	SCE uses historical data which may not be an indicator of future equipment failure rates.	POI
General Vegetation Contact Rates	SCE bases its vegetation contact rates on its predictive model for Contact from Foreign Object (CFO) subcomponent using 2015-2023+ CFO outages for vegetation sub drivers.	SCE uses machine learning algorithms to develop predictive models for vegetation contact that are validated and tested for accuracy for inclusion in our probabilistic assessment for risk calculations.	SCE uses historical data which may not be an indicator of future vegetation contact rates.	POI
Height of Electrical Equipment in the Service Territory	SCE uses current asset condition attributes (e.g., age, voltage, manufacturer, height of pole, etc.) as variables utilized in the machine learning algorithms. The height of electrical	SCE's machine learning models use historical environmental, physical, and electrical variables paired with their actual records of failures to derive statistical insights.	Height of equipment is based on pole height of associated asset and may not reflect actual installation height.	POI

	Assumption	Justification	Limitation	Applicable Models
	equipment is governed by the applicable regulations in GO 95.			
Stability of the Atmosphere	Atmospheric instability, as it related to wildfire propagation after initial ignition, is not considered in the model.	The wildfire propagation model is a surface model is not directly coupled with the atmosphere. It assumes that the heat flux generated by the wildfire will not modify local atmospheric conditions and thus create additional fuel moisture dryness (e.g., pre-heating) in any way.	The intent of the model is to capture the fire propagation at the time of the ignition event through an 8-hour simulated burn period. The resulting wildfire is assumed to be fully developed with fire acceleration, flashover, or decay not being considered.	Wildfire Consequence
Vegetation Fuels	SCE uses the Live/Dead Fuel Moisture Data from the FWD selected. These variables include Dead moisture content, (1hr, 10hr, 100hr, 1000hr) herbaceous moisture content, and live woody moisture content. (See Section 8.3.5).	Dead fuel moisture is calculated using the Nelson model which is widely used among fire agencies nationwide. Live fuel moisture is calculated using a machine learning approach that was in part developed by SCE.	Modeling fuel moisture is affected by the same limitations that are common in numerical modeling. In addition to the biases and other forecast errors associated with parameters needed to calculate fuel moisture such as temperature, atmospheric moisture, soil moisture, evaporation rates, etc., uncertainties within the physical processes of vegetation phenology compound the errors associated with vegetation moisture outputs	Wildfire Consequence

	Assumption	Justification	Limitation	Applicable Models
Vegetation Fuels	Fuels are based on the Timber fuel layers, including an additional 19 custom fuel models. Additional WUI and Non-Forested Land Use are based on customized fuel models representing fire propagation in those locations. (Technosylva, 2020).	These fuel models were developed through daily validation of fuels with fire behavior data from CAL FIRE and California National Guard FireGuard data.	These fuel models are static and only represent a snapshot in time at a 30m x 30m resolution. Given limitations in the spatial and temporal granularity of this information (e.g., changes in suburban development between the time the data was captured to present day), this data may not accurately represent details in land/vegetation types at the time of the ignition.	Wildfire Consequence
Combination of Risk Components/Weighting of Attributes	The natural unit consequences resulting from wildfire simulations are translated into safety, reliability and consequence scores based on guidance from the most recent applicable Risk Informed Decision- Making Framework Proceeding (RDF)	SCE developed its MAVF based on the principles as set forth in the S-MAP settlement. Appendix B provides further discussion and justification for each of the components. SCE is an active participant in the CPUC's RDF.	The attributes are based on observable data and may not reflect other qualitative factors such as egress or customer satisfaction; factors which may not lend themselves to this type of framework. They may also not reflect of associated risk tolerance standards as set forth in other Commission and/or Legislative guidance (e.g., SB 901).	Wildfire Consequence
Wind Load Capacity for Electrical Equipment	SCE assumes the wind load capacity for its electrical equipment is, at minimum, aligned with applicable GO 95 requirements.	SCE is required to maintain the system based on applicable CPUC operating practices.	Equipment failure can occur in both high wind and low/no wind conditions and can be the result of difficult to predict factors, such as animal and vehicles contact.	POI
Number, extent, and type of community assets at risk	Not Applicable	Communities at Risk are not spatially granular enough to adequately represent wildfire risk. For example, the City of Los Angeles is considered a Community at Risk (CAR), though the	Not Applicable, see comment at left.	Wildfire Consequence

	Assumption	Justification	Limitation	Applicable Models
		vast majority of the city is not exposed to wildland fires. Please also see Section 5.4.		
Proxies for estimating impact on customers and communities	SCE assumes only direct impacts to customers.	SCE uses a ratio of 256 structures impacted to one fatality, and a ratio of 107 structures impacted to one serious injury to determine its safety impact.	These estimates are based on recent historical fire information in Southern California and only include reported data. They do not include any potential indirect or unreported impacts.	Wildfire Consequence
Extent, distribution, and characteristics of vulnerable populations	SCE utilizes an AFN/NRCI multiplier on the safety attribute of MAVF.	The AFN/NRCI multiplier is a relative ranking of vulnerability by populations served on individual circuits.	AFN/NRCI weights each population set (AFN customers/NRCI customers) equally and does not differentiate between customer class. Additionally, SCE does not account for customer self-generation capabilities.	Wildfire Consequence

5.3 Risk Scenarios

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

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

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

Each scenario must consider:

- ***Local relevance:** Heterogeneous conditions (e.g., assets, equipment, topography, vegetation, weather) that vary over the landscape of the electrical corporation's service territory at a level sufficiently granular to permit understanding of the risk at a specific location or for a specific circuit segment. For example, statistical wind loads must be calculated based on wind gusts considering the impact of nearby topographic and environmental features, such as hills, canyons, and valleys.*
- ***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).*

Overview

SCE uses a design basis scenario in its MARS and IWMS Risk Frameworks that reflects wind loading conditions, weather conditions, and vegetation conditions. As described further below, SCE's approach incorporates elements of five of the design scenarios defined by OEIS for the risk assessment analysis that informs mitigation prioritization and selection.

SCE has also developed a scenario called Climate 2030 that represents an Extreme-Event/High Uncertainty scenario. This scenario is not currently used and is still under evaluation. It is intended to help SCE assess if climate change, as well as any resulting changes in wildfire consequence, may influence our existing grid hardening strategy.

SCE provides further detail on both its design basis and extreme event scenarios in the sections immediately following.

5.3.1 Design Basis Scenarios

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

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

- ***Wind Load Condition 1: Baseline:*** *The baseline wind load condition the electrical corporation uses in design, construction, and maintenance relative to GO 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 three-year WMP cycle (i.e., 60-year return interval).*
- ***Wind Load Condition 4: Credible Worst Case:*** *Wind gusts with a probability of exceedance of 1 percent over the three-year WMP cycle (i.e., 300-year return interval).*

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

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

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

- ***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.*
- ***Weather Condition 2: Long-Term Conditions:** The statistical weather analysis is representative of fire seasons covering the full historical record and adapted to forecasted climate conditions.*

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

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

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

- ***Vegetation Condition 1: Existing Fuel Load:** The wildfire hazard evaluated with the existing fuel load within the service territory, including existing burn scars and fuel treatments that reduce the near-term fire hazard.*
- ***Vegetation Condition 2: Short-Term Forecasted Fuel Load:** The wildfire hazard evaluated considering the changes in expected fuel load over the three-year WMP cycle, including regrowth of previously burned and treated areas.*
- ***Vegetation Condition 3: Long-Term Extreme Fuel Load:** The wildfire hazard evaluated considering the long-term potential changes in fuels throughout the service territory. This includes regrowth of previously burned and treated areas and changes in predominant fuel types.*

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

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

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

- ***Scenario ID:*** *Identification of each design basis scenario included within its risk modeling (e.g., Scenario 1, Scenario 2)*
- ***Design Scenario:*** *The components of each scenario used, as described above or by the electrical corporation (e.g., Weather Condition 1, Vegetation Condition 1)*
- ***Purpose:*** *How the output of the scenario is used within risk modeling, if applicable*

Table 5-2 provides an example.

Design Basis Scenarios

SCE utilizes a FWD selection methodology representative of all observed fire weather conditions based on its 40+ year historical climatology. See additional details, below. We believe this methodology provided sufficient granularity to guide the deployment of individual mitigations.

Table 5-2: SCE Summary of Design Basis Scenarios

Scenario ID	**Design Scenarios (Components)**	**Purpose**
WL1	Wind Loading Condition 1	For Wind and Weather loading conditions, see discussion of FWD selection process in previous sections.
WL2	Wind Loading Condition 2	
WC2	Weather Condition 2	
VC1	Vegetation Condition 1	For Vegetation conditions, see discussion of Fuel development in previous sections.
VC3	Vegetation Condition 3	

5.3.1.1 Wind Loading Conditions

WL1: Baseline

The baseline wind load condition the electrical corporation use in design, construction, and maintenance relative to GO 95, Rule 31.1.

SCE FWD selection methodology uses weather and wind scenarios that meet these conditions for all FCZs, including those required to guide the design, construction, and maintenance relative to GO 95, Rule 31.1 See Section 5.2.2.2.2.2 and Appendix B: Supporting Documentation for Risk Methodology and Assessment.

Following the 2011 San Gabriel Valley windstorm, SCE was directed by the CPUC to conduct a pole loading study to assess the likely wind conditions to comply with the relevant sections of ASCE/SEI 7-10 “Minimum Design Loads for Buildings and Other Structures” and California GO 95 “Overhead Electric Line Construction.”[67] These weather and wind conditions reflect the same 41 fire weather scenarios used in the construction of the CPUC HFTD maps.

The result of this study was a composite wind loading map for peak wind speeds, both with and without consideration of relative humidity and temperature, for wind velocities at 20-foot elevations (3 second gusts) based on a 50-year return interval (i.e., a 2% chance of occurrence per year). SCE uses this information in its FWD selection process.

WL2: 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).

SCE FWD selection methodology uses weather and wind scenarios that meet these conditions for all FCZs based on observed wind and weather conditions in its 40+ year historical climatology. See Section 5.2.2.2.2 and Appendix B: Supporting Documentation for Risk Methodology and Assessment for additional information.

These wind conditions include those required for the purpose of evaluating potential PSPS de-energization decisions. See Section 10.6 for additional detail.

WL3: Extreme

Wind gusts with a probability of exceedance of 5 percent over the three-year WMP cycle (i.e., 60-year return interval).

SCE FWD selection methodology uses weather and wind scenarios that meet these conditions for all FCZs based on observed wind and weather conditions in its 40+ year historical climatology. These include those with wind gusts with a probability of exceedance of 5 percent. See Section 5.2.2.2.2.2 and Appendix B: Supporting Documentation for Risk Methodology and Assessment for additional information.

SCE is piloting a methodology to determine how FWD frequency may change based on future conditions based on guidance in the CPUC Climate Change Adaptation Proceeding, as well as data from the California Fifth Climate Change Assessment. See Section 3.7, as well as Appendix D: Areas for Continued Improvement. ACI SCE 23B-04 Incorporation of Extreme Weather Events into Planning Models, for additional information.

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67 See I.14-03-004. Order Instituting Investigation on the Commission’s Own Motion into the Operations and Practices of Southern California Edison Company Regarding the Acacia Avenue Triple Electrocution Incident in San Bernardino County and the Windstorm of 2011.

For the reasons stated above, as well as given the long effective useful lives (EUL) of utility assets, SCE does not believe it is necessary to develop a separate scenario specifically for the three-year WMP cycle utilizing this design scenario.

WL4: Credible Worst Case

Wind gusts with a probability of exceedance of 1 percent over the three-year WMP cycle (i.e., 300-year return interval).

SCE FWD selection methodology uses weather and wind scenarios that meet these conditions for all FCZs based on observed wind and weather conditions in its 40+ year historical climatology. These include Credible Worst-Case conditions, (e.g., wind gusts with a probability of exceedance of 1 percent over the three-year WMP cycle (i.e., 300-year return interval)). See Section 5.2.2.2.2.2 and Appendix B: Supporting Documentation for Risk Methodology and Assessment for additional information.

SCE is piloting a methodology to determine how FWD frequency may change based on future conditions based on guidance in the CPUC Climate Change Adaptation Proceeding, as well as data from the California Fifth Climate Change Assessment. See Section 3.7, as well as Appendix D: Areas for Continued Improvement. ACI SCE 23B-04 Incorporation of Extreme Weather Events into Planning Models, for additional information.
SCE also notes that the guideline to include Credible Worst-Case scenarios may conflict with the premise of ACI SCE-25U-01 Calculating Risk Scores Using Maximum Consequence Values. See SCE response in Appendix D: Areas for Continued Improvement. SCE-25U-01 Calculating Risk Scores Using Maximum Consequence Values for additional information.

5.3.1.2 Weather Conditions

WC1: 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.

SCE FWD selection methodology uses weather and wind scenarios that meet these conditions for all FCZs based on observed wind and weather conditions in its 40+ year historical climatology. See Section 5.2.2.2.2.2 and Appendix B: Supporting Documentation for Risk Methodology and Assessment.

SCE does not use a short-term, forward-looking weather scenario to prioritize grid hardening activities given the long effective useful life (EUL) of those assets. Short-term weather trends (e.g., three years) are highly variable and contain a significant amount of uncertainty. Additionally, short-term weather trends are generally not representative of the ensemble average of longer term (e.g., 10 - 30 year) climatological conditions. Because of this, SCE does not anticipate utilizing this design scenario.

For the reasons stated above, SCE does not believe it is necessary to develop a separate scenario specifically for the three-year WMP cycle utilizing this design scenario.

WC2: Long-Term Conditions

The statistical weather analysis is representative of fire seasons covering the full historical record and adapted to forecasted climate conditions.

SCE FWD selection methodology uses weather and wind scenarios that meet these conditions for all FCZs based on observed wind and weather conditions in its 40+ year historical climatology. See Section 5.2.2.2.2.2 and Appendix B: Supporting Documentation for Risk Methodology and Assessment.

SCE also notes that the guideline to include Credible Worst-Case scenarios may conflict with the premise of ACI SCE-25U-01. Calculating Risk Scores Using Maximum Consequence Values. See SCE response in Appendix D: Areas for Continued Improvement SCE-25U-01. Calculating Risk Scores Using Maximum Consequence Values for additional information.

5.3.1.3 Vegetative Conditions

VC1: Existing Fuel Load

The wildfire hazard evaluated with the existing fuel load within the service territory, including existing burn scars and fuel treatments that reduce the near-term fire hazard.

SCE does not use existing vegetative fuel loads to prioritize grid hardening activities given the long EUL of those assets. Existing vegetation trends (e.g., present day) are only present in the environment for short amounts of time. See Appendix B: Supporting Documentation for Risk Methodology and Assessment.

SCE does, however, note that it uses scenarios that reflect Vegetation Condition 1 for the purpose of evaluating potential PSPS de-energization decisions.

VC2: Short-Term Forecasted Fuel Load

The wildfire hazard evaluated considering the changes in expected fuel load over the three-year WMP cycle, including regrowth of previously burned and treated areas.

SCE does not use short-term forward-looking vegetative fuel loads to prioritize grid hardening activities given the long EUL of those assets. See Appendix B: Supporting Documentation for Risk Methodology and Assessment.

Short-term vegetation trends (e.g., three years), including regrowth in recent fire scars and prescribed burns are highly variable and are only present in the environment for shorts amount of time.

While these may, in the short term, reduce the intensity of wildfire events, they do not impact fuels for an extended enough period to represent longer term (e.g., 10 - 30 year) environmental conditions. See Appendix B: Supporting Documentation for Risk Methodology and Assessment.

SCE does, however, note that it uses scenarios that reflect Vegetation Condition 2 for the purpose of evaluating potential PSPS de-energization decisions. See Section 10.6 for additional detail.

VC3: Long-Term Extreme Fuel Load

The wildfire hazard evaluated considering the long-term potential changes in fuels throughout the service territory. This includes regrowth of previously burned and treated areas and changes in predominant fuel types.

SCE uses a 2035 fuel layer which aligns with Vegetation Condition 3. See Appendix B: Supporting Documentation for Risk Methodology and Assessment for additional information.

While SCE does not believe that these fuel conditions are extreme, long-term forward-looking vegetative fuel load is the most useful in prioritizing grid hardening activities given the long EUL of the assets. Additionally, this fuel loading (~10 year) reflects an appropriate level of fuel regrowth in areas subject to major fire events (e.g., greater than 5,000 acres).

5.3.2 Extreme-Event/High Uncertainty Scenarios

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

- *Longer-term scenarios with higher uncertainty (e.g., climate change impacts, population migrations, extended drought)*
- *Multi-hazard scenarios (e.g., ignition from another source during a PSPS)*
- *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 5.3.1, the potential for high consequences from extreme events may provide additional insight into the mitigation prioritization described in Section 6.

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

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

Overview: Extreme Event Scenarios

Table 5-3: SCE Summary of Extreme-Event Scenarios

Scenario ID	Extreme-Event Scenario	Purpose
ES1: FireSight 8 (Climate)	Climate Change 2050 (Wind) Climate Change 2050 (Weather) Vegetation Condition 3	Determine how the patterns of utility ignition risk may change in the future using CPUC guidance, while leveraging existing wildfire simulation architecture.

Longer-Term Scenarios with Higher Uncertainty

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

ES1: FireSight 8 (Climate)

FireSight 8 (Climate) is a type of longer-term scenario with higher uncertainty. It consists of two extreme event scenarios: Climate Change 2050 (Wind and Weather) and Vegetation Condition 3.

Climate Change 2050 (Wind and Weather)

SCE leveraged relevant Global Climate Models (GCMs) to represent 2.0°C of warming based on Shared Socioeconomic Pathway (SSP), SSP 3-7.0. These hourly weather and wind data will be used to create a synthetic year 2050 gridded climatology. This gridded synthetic climatology will be used to assess any future changes to FCZ-specific weather and wind patterns from present day conditions. For more information see Section 3.7.

Vegetation Condition 3

To help ensure a like-for-like comparison with present day conditions, SCE used the same 2035 fuel map used for existing grid hardening activities. Considering the uncertainty regarding future potential changes to Land Use Land Cover (LULC), such as potential increases in the WUI and/or desertification, as well as other potential fuel changes, SCE did not create another fuel model.

Purpose

SCE has developed a forward-looking climate change scenario using its existing FireSight 8 architecture to represent how weather and wind conditions may change from present day (historical) conditions.

The Commission directed utilities to perform a pilot designed to integrate climate change into utility risk models in Phase III of the RDF proceeding.[68] SCE notes that the Phase III Decision

68 D.24-05-064, Phase III.

explicitly requires utilities to "seek to avoid, if possible, any long-term asset investment strategy that would be at risk in the future because of climate change impacts."[69]

SCE is required to report the results of this Climate Change Pilot whitepaper no later than May 15, 2026, concurrent with its 2026 RAMP and CAVA filings.

In guidance in the Climate Change Adaptation (CCA) Proceeding, the Commission also required utilities to use SSP 3-7.0 as the reference scenario applicable to all RAMP, GRC, and long-term infrastructure planning and to study Global Warming Levels (GWL)s of 2.0°C. Under SSP 3-7.0 reference scenario timing, a GWL of 2.0°C is projected between 2035 and 2058.[70]

Methodology

For this analysis, SCE will use reference GCM data to represent a synthetic year 2050 climatology to simulate forward looking climate impacts. These forward-looking wildfire impacts can then be used to:

- Determine if there is an increase in frequency in FWD by FCZ, and if so, how pronounced are these increases.
- Determine if there is an increase in the resulting consequences from these simulations, using climate data to simulate future weather, wind, and fuel conditions. To ensure a *like for like* comparison with present day conditions, SCE will produce similar truncated simulations for both 8- and 24-hours for each ignition point and asset.

69 D.24-05-064. Ordering Paragraph 3. (d) The IOUs should seek to avoid, if possible, any long-term asset investment strategy that would be at risk in the future because of climate change impacts.

70 This guidance supersedes SCE's previous approach to using Representative Concentration Pathway (RCP) in SCE's previous Climate 2030 analysis.

5.4 Summary of Risk Models

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

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

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

Table 5-4: SCE Summary of Risk Models

ID	Risk Component	Design Scenario(s)	Key Inputs	Source of Inputs (Data and/or Models)	Key Outputs	Units
R1	Overall utility risk	WL1, WL2, WL3, WL4, WC2 VC3	Wildfire risk Reliability risk	See related models	Risk at a specific location, as granular as possible (i.e., circuit segment, pole)	Risk at individual assets
R2	Wildfire risk	WL1, WL2, WL3, WL4, WC2 VC3	Ignition likelihood Ignition consequence	See related models	Wildfire risk at a specific location	Risk at individual assets
R3	Outage program risk	WL1, WL2, WL3, WL4, WC2 VC3	PSPS risk PEDS risk	See related models	Outage program risk at a specific location	Risk at individual assets Probability of de-energization (annualized)
IRC1	Wildfire likelihood	WL1, WL2, WL3, WL4, WC2 VC3	Burn likelihood Ignition likelihood	See related models	Likelihood of a wildfire occurring given an ignition at a specific location	NA Probability of ignition (annualized)

ID	Risk Component	Design Scenario(s)	Key Inputs	Source of Inputs (Data and/or Models)	Key Outputs	Units
IRC2	Ignition likelihood	WL1, WL2, WL3, WL4, WC2 VC3	Equipment caused likelihood of ignition Contact by vegetation likelihood of ignition Contact by object likelihood of ignition	See related models	Number of ignitions at a specific location	Probability of ignition (annualized) Probability of ignition (annualized) Probability of ignition (annualized)
IRC3	Wildfire consequence	WL1, WL2, WL3, WL4, WC2 VC3	Wildfire hazard intensity Wildfire exposure potential Wildfire vulnerability	See related models	Adverse effects at a specific location per wildfire	See Section 5.2 for additional information
IRC4	PSPS risk	WL1, WL2, WL3, WL4, WC2 VC3	PSPS likelihood PSPS consequence	See related models	PSPS risk at a specific location	Risk at individual assets
IRC5	PSPS likelihood	WL1, WL2, WL3, WL4 WC2 VC3	Wind gust velocity Vegetation moisture	Weather model	Likelihood of PSPS at a specific location per year	Frequency/year
		WL1, WL2, WL3, WL4 WC2 VC3	Equipment parameters Presence of mitigation	Asset database	Likelihood of PSPS at a specific location per year	Frequency/year

ID	Risk Component	Design Scenario(s)	Key Inputs	Source of Inputs (Data and/or Models)	Key Outputs	Units
		WL1, WL2, WL3, WL4 WC2 VC3	Current status Operating conditions	Data from inspections, work order history, and real-time monitoring systems	Likelihood of PSPS at a specific location per year	Frequency/year
IRC6	PSPS consequence	NA	PSPS exposure potential Vulnerability of community to PSPS	See related models	Adverse effects at a specific location per PSPS	See Section 5.2 for additional information
IRC7	PEDS outage risk	WL1, WL2, WL3, WL4, WC2 VC3	PEDS likelihood PEDS consequence	See related models	PEDS outage risk at a specific location	Risk at individual assets
IRC8	PEDS outage likelihood	WL1, WL2, WL3, WL4 WC2 VC3	Wind gust velocity Vegetation moisture	Weather model	Likelihood of PEDS outage at a specific location per year	Frequency/year
		WL1, WL2, WL3, WL4 WC2 VC3	Equipment parameters Presence of mitigation	Asset database	Likelihood of PEDS outage at a specific location per year	Frequency/year
		WL1, WL2, WL3, WL4 WC2 VC3	Current status Operating conditions	Data from inspections, work order history, and real-time monitoring systems	Likelihood of PEDS outage at a specific location per year	Frequency/year

ID	Risk Component	Design Scenario(s)	Key Inputs	Source of Inputs (Data and/or Models)	Key Outputs	Units
IRC9	PEDS outage consequence	NA	PEDS exposure potential Vulnerability of community to PEDS	See related models	Adverse effects at a specific location per PEDS outage	(-)/outage location
FRC1	Equipment caused ignition likelihood	WL1, WL2, WL3, WL4 WC2 VC3	Wind gust velocity Vegetation moisture	Weather model	Likelihood of equipment, including failure, causing an ignition	Ignitions/year
		WL1, WL2, WL3, WL4 WC2 VC3	Equipment parameters Presence of mitigation	Asset database	Likelihood of equipment, including failure, causing an ignition	Ignitions/year
		WL1, WL2, WL3, WL4 WC2 VC3	Current status Operating conditions	Data from inspections, work order history, and real-time monitoring systems	Likelihood of equipment, including failure, causing an ignition	Ignitions/year
FRC2	Contact from vegetation ignition likelihood	WL1, WL2, WL3, WL4 WC2 VC3	Wind gust velocity Vegetation moisture	Weather model	Likelihood of vegetation contact causing an ignition	Ignitions/year
		WL1, WL2, WL3, WL4 WC2 VC3	Vegetation parameters	Vegetation database	Likelihood of vegetation contact causing an ignition	Ignitions/year

ID	Risk Component	Design Scenario(s)	Key Inputs	Source of Inputs (Data and/or Models)	Key Outputs	Units
		WL1, WL2, WL3, WL4 WC2 VC3	Current status	Data from inspections and vegetation treatment	Likelihood of vegetation contact causing an ignition	Ignitions/year
FRC3	Contact from object ignition likelihood	WL1, WL2, WL3, WL4 WC2 VC3	Wind gust velocity Vegetation moisture	Weather model	Likelihood of non-vegetation object contact causing an ignition	Ignitions/year
		WL1, WL2, WL3, WL4 WC2 VC3	Historic risk events	Data from previous risk events	Likelihood of non-vegetation object contact causing an ignition	Ignitions/year
FRC4	Burn likelihood	WL1, WL2, WL3, WL4 WC2 VC3	Topography	LANDFIRE	Likelihood of a fire reaching a location from a nearby but unknown ignition point	NA – see FWD Section 5.2
		WL1, WL2, WL3, WL4 WC2 VC3	Statistical profile of sustained wind speeds	Weather model	Likelihood of a fire reaching a location from a nearby but unknown ignition point	NA – See FWD Section 5.2

ID	Risk Component	Design Scenario(s)	Key Inputs	Source of Inputs (Data and/or Models)	Key Outputs	Units
		WL1, WL2, WL3, WL4 WC2 VC3	Vegetation	LANDFIRE, adapted based on LiDAR (light detection and ranging) data	Likelihood of a fire reaching a location from a nearby but unknown ignition point	NA – see FWD Section 5.2
FRC5	Wildfire hazard intensity	WL1, WL2, WL3, WL4 WC2 VC3	Topography	LANDFIRE	Intensity of a fire at a specific location	NA – see FWD Section 5.2
		WL1, WL2, WL3, WL4 WC2 VC3	Sustained wind speeds	Weather model	Intensity of a fire at a specific location	NA – see FWD Section 5.2
		WL1, WL2, WL3, WL4 WC2 VC3	Vegetation	LANDFIRE, adapted based on LiDAR data	Intensity of a fire at a specific location	NA – see FWD Section 5.2
FRC6	Wildfire exposure potential	NA	Topography	LANDFIRE	Structures, people, and critical infrastructure at a specific location	CPUC HFTD Map
		NA	Land use	Remote sensing	Structures, people, and critical infrastructure at a specific location	Fuel Types

ID	Risk Component	Design Scenario(s)	Key Inputs	Source of Inputs (Data and/or Models)	Key Outputs	Units
		NA	Population information	Census	Structures, people, and critical infrastructure at a specific location	Quantity/Location
FRC7	Wildfire vulnerability	NA	Vulnerable populations (access and functional needs population [AFN], limited English proficiency [LEP], elderly)	Census and surveys	Structures, people, and critical infrastructure at a specific location	Quantity/Location
		NA	Land use	Remote sensing	Structures, people, and critical infrastructure at a specific location	Quantity/Location
		NA	Critical infrastructure	Local municipalities	Structures, people, and critical infrastructure at a specific location	Quantity/Location
FRC8	PSPS exposure potential	NA	Topography	LANDFIRE	Structures, people, and critical infrastructure at a specific location	CPUC HFTD Map

ID	Risk Component	Design Scenario(s)	Key Inputs	Source of Inputs (Data and/or Models)	Key Outputs	Units
		NA	Land use	Remote sensing	Structures, people, and critical infrastructure at a specific location	Fuel Types
		NA	Population information	Census	Structures, people, and critical infrastructure at a specific location	Quantity/Location
FRC9	Vulnerability of community to PSPS	NA	Vulnerable populations (AFN, LEP, elderly)	Census and surveys	Structures, people, and critical infrastructure at a specific location	Quantity/Location
		NA	Land use	Remote sensing	Structures, people, and critical infrastructure at a specific location	Quantity/Location
		NA	Critical infrastructure	Local municipalities	Structures, people, and critical infrastructure at a specific location	Quantity/Location
FRC10	PEDS outage exposure potential	NA	Topography	LANDFIRE	Structures, people, and critical infrastructure at a specific location	CPUC HFTD Map

ID	Risk Component	Design Scenario(s)	Key Inputs	Source of Inputs (Data and/or Models)	Key Outputs	Units
		NA	Land use	Remote sensing	Structures, people, and critical infrastructure at a specific location	Fuel Types
		NA	Population information	Census	Structures, people, and critical infrastructure at a specific location	Quantity/Location
FRC11	PEDS outage vulnerability	NA	Vulnerable populations (AFN, LEP, elderly)	Census and surveys	Structures, people, and critical infrastructure at a specific location	Quantity/Location
		NA	Land use	Remote sensing	Structures, people, and critical infrastructure at a specific location	Quantity/Location
		NA	Critical infrastructure	Local municipalities	Structures, people, and critical infrastructure at a specific location	Quantity/Location

5.5 Risk Analysis Results and Presentation

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

The risk presentation must include the following:

- *Summary of electrical corporation-identified high fire risk areas in the service territory.*
- *Geospatial map of the top risk areas within the High Fire Risk Area (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.*
- *Tabular summary of key metrics across the service territory.*

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

5.5.1 Top Risk Areas within the HFRA

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

5.5.1.1 Geospatial Maps of Top-Risk Areas within the HFRA

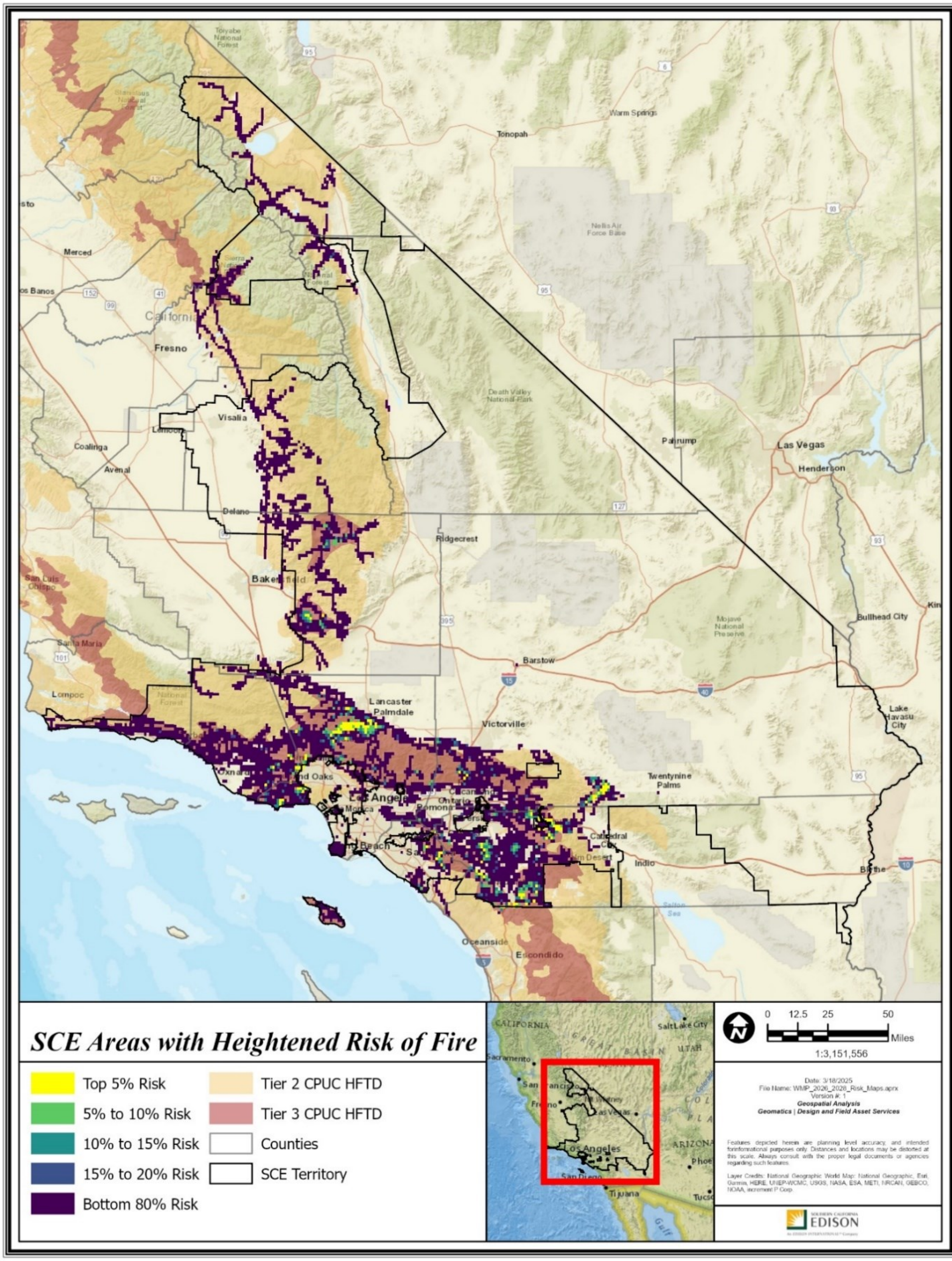
The electrical corporation must evaluate the outputs from its risk modeling to identify top risk areas within its HFRA (independent of where they fall with respect to the HFTD). The electrical corporation must provide geospatial maps of these areas in accordance with the mapping requirements in the WMP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

The maps must fulfill the following requirements:

- ***Risk levels:** Levels must be selected to show the five distinct levels, with the values based on the following:*
    - *Top five percent of overall utility risk values in the HFRA*
    - *Top five to ten percent of overall utility risk values in the HFRA*
    - *Top ten to 15 percent of overall utility risk values in the HFRA*
    - *Top 15 to 20 percent of overall utility risk values in the HFRA*
    - *Bottom 80 percent of overall utility risk values in the HFRA*

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

Figure SCE 5-54: Map of Top-Risk Areas within SCE HFRA[71]



71 Risk data as of 03/19/2025 calculated with the MARS Framework.

5.5.1.2 Proposed Updates to the HFTD

In this section, the electrical corporation must discuss the differences between the electrical corporation-identified top-risk areas within the HFRA and the existing CPUC-approved

HFTD. The HFRA must be comprised of areas identified by the electrical corporations that its risk analysis indicates are at a higher risk than indicated in the current HFTD. Any proposed changes to the HFTD must be mapped in accordance with the requirements in the previous sub-section.

This discussion at a minimum must include:

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

On November 8, 2024, SCE filed a Petition for Modification (PFM)[72] to CPUC Rulemaking 15-05-006 requesting that specific areas of SCE's service territory be either added or removed from the HFTD to align with our updated understanding of wildfire risk. SCE's proposed removals and additions would sum to 40 square miles of increase to the HFTD, representing a 0.07% net increase of HFTD within SCE's service territory. At the time of this filing, R.15-05-006 remains open and the CPUC has yet to issue a decision on SCE's 2024 PFM.[73]

SCE has iterated its analytical techniques to review land use, land cover, and terrain and leverage public data sources from Silvis Lab and the U.S. Forest Service to facilitate independent review and replication of SCE's methodology. SCE's analysis compared the current HFTD boundaries with an updated fuel map based on more recent and spatially granular data. SCE used this comparison to identify locations outside of the current HFTD boundaries containing burnable fuels which could lead to ignitions that may spread rapidly. Similarly, SCE used map comparison to identify areas within its service territory, currently designated as HFTD, which do not contain burnable fuel loads and may not warrant the HFTD designation. This produced a subset of specific areas called polygons which SCE analyzed extensively, encompassing hundreds of hours spent reviewing multiple data sources, assessing local conditions, conducting field surveys, holding meetings and discussions, and vetting recommendations with senior executives and other key stakeholders.

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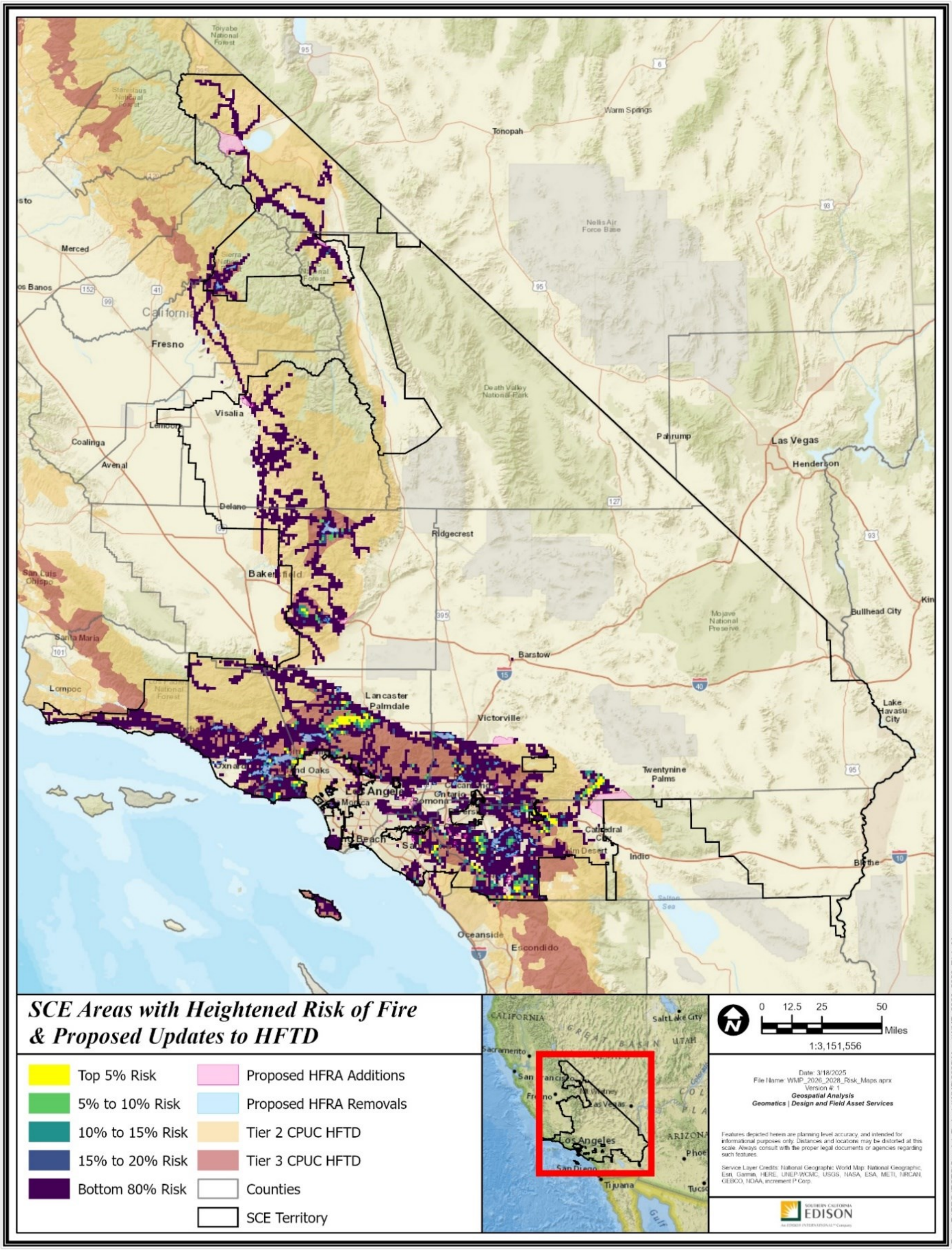
72 Available at https://www.sce.com/wmp.

73 California Public Utilities Commission Decision 25-01-037 *Denying Petition to Modify Decisions 17-01-009, 17-12-024 and 20-12-030*, pp. 1, 14. Accessible via: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M556/K074/556074295.PDF.

Recommendations to add or remove polygons from the HFTD and change polygon boundaries were based on the following inputs:

- Satellite-based imagery supplemented with SCE field surveys and drone imagery
- Technosylva Fuels 2030 data
- eESRI terrain slope in ArcGIS
- Historical weather and fire information
- Silvis Labs Wildland-Urban Interface ("WUI") data
- The U.S. Department of Agriculture (USDA) / U.S. Forest Service (USFS) Wildfire Hazard Potential Index and probability of flame lengths greater than 8 feet high in the event of a fire

Figure SCE 5-55: Map of Top-Risk Areas within the SCE HFRA and SCE Proposed Updates to the HFTD[74]



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74 Risk data as of 03/19/2025 calculated with the MARS Framework.

From an operational perspective, while SCE's PFM is pending, SCE intends to begin to treat its proposed additions to the HFTD as eligible for PSPS as a measure of last resort when conditions present unacceptable wildfire risk. SCE intends to implement enhanced asset inspections and maintenance schedules, vegetation management activities, and other programs aimed at mitigating wildfire risk in the areas that SCE proposes to be added to the HFTD after the CPUC issues a final decision on SCE's PFM.

Additionally, from an operational perspective, SCE intends to continue to treat proposed removals from the HFTD as HFTD until the CPUC issues its decision, maintaining existing mitigations.

5.5.2 Top Risk-Contributing Circuits/Segments/Spans

The electrical corporation must provide a summary table showing the highest-risk circuits, segments, or spans[37] 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.*
- ***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 one percent of the total overall utility risk; or*
2. *Is in the top five percent of highest risk circuits/segments/spans when all circuits/segments/spans are ranked individually from highest to lowest risk.*

The electrical corporation must include each circuit, segment, or span that significantly contributes to risk in Table 5-5. If this table is longer than two pages once populated, the electrical corporation must append the table.

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

Table 5-5: SCE Summary of Top-Risk Circuits[75]

Risk Ranking	Circuit, Segment, or Span ID	Overall Utility Risk Score per HFRA Mile	Wildfire Risk Score per HFRA Mile	Outage Program Risk Score per HFRA Mile	Top Risk Contributors	Total Miles	Version of Risk Model Used
1	TUNGSTEN	0.96292	0.96289	0.00003	EFF Risk, CFO Other Risk	0.83	POI 2024, FireSight 8
2	PHEASANT	0.29491	0.29491	0.00000	EFF Risk, CFO Other Risk	10.80	POI 2024, FireSight 8
3	LOUCKS	0.22597	0.22597	0.00000	EFF Risk, CFO Other Risk	5.90	POI 2024, FireSight 8
4	PASCAL	0.21017	0.21017	0.00001	CFO Other Risk, EFF Risk	10.78	POI 2024, FireSight 8
5	DAVENPORT	0.18979	0.18979	0.00000	EFF Risk, CFO Other Risk	67.96	POI 2024, FireSight 8
6	CERRITO	0.18868	0.18868	0.00005	EFF Risk, CFO Other Risk	1.86	POI 2024, FireSight 8
7	RAYBURN	0.18688	0.18688	0.00001	EFF Risk, CFO Other Risk	11.31	POI 2024, FireSight 8
8	SHOVEL	0.17730	0.17729	0.00000	CFO Other Risk, EFF Risk	45.63	POI 2024, FireSight 8
9	PELONA	0.17628	0.17627	0.00005	CFO Other Risk, EFF Risk	1.70	POI 2024, FireSight 8
10	GUFFY	0.17512	0.17512	0.00001	CFO Other Risk, EFF Risk	4.46	POI 2024, FireSight 8
11	STORES	0.16823	0.16823	0.00000	EFF Risk, CFO Other Risk	24.97	POI 2024, FireSight 8
12	PURCHASE	0.16090	0.16090	0.00000	EFF Risk, CFO Other Risk	3.51	POI 2024, FireSight 8
13	ENERGY	0.15185	0.15185	0.00000	CFO Other Risk, EFF Risk	29.31	POI 2024, FireSight 8
14	ARIEL	0.15004	0.15004	0.00011	EFF Risk, CFO Other Risk	0.33	POI 2024, FireSight 8
15	BODKIN	0.13442	0.13442	0.00001	EFF Risk, CFO Other Risk	1.74	POI 2024, FireSight 8
16	CASCADE	0.13233	0.13233	0.00001	CFO Other Risk, EFF Risk	6.83	POI 2024, FireSight 8
17	IDA	0.12510	0.12510	0.00001	EFF Risk, CFO Other Risk	10.76	POI 2024, FireSight 8
18	FINGAL	0.12280	0.12280	0.00000	EFF Risk, CFO Other Risk	36.95	POI 2024, FireSight 8
19	POPPET FLATS	0.12032	0.12032	0.00000	EFF Risk, CFO Other Risk	33.37	POI 2024, FireSight 8
20	STONEMAN	0.11761	0.11761	0.00001	EFF Risk, CFO Other Risk	27.15	POI 2024, FireSight 8
21	PIONEERTOWN	0.11151	0.11151	0.00000	EFF Risk, CFO Other Risk	60.81	POI 2024, FireSight 8
22	PICK[76]	0.10405	0.10405	0.00000	CFO Other Risk, EFF Risk	43.15	POI 2024, FireSight 8
23	IRVINGTON	0.10252	0.10251	0.00003	CFO Other Risk, EFF Risk	0.25	POI 2024, FireSight 8
24	PICONI	0.10155	0.10155	0.00001	EFF Risk, CFO Other Risk	19.67	POI 2024, FireSight 8
25	SNOWCREEK	0.09969	0.09969	0.00000	EFF Risk, CFO Other Risk	1.77	POI 2024, FireSight 8

75 Risk scores as of December 11, 2024 calculated via the MARS Framework. Values for Overall Utility Risk Score, Wildfire Risk Score, and Outage Program Risk Score represent average MARS value per circuit mile within HFRA. Top Risk Contributors indicates the top two risk drivers (listed in order). SCE updated this table on March 18, 2025.

76 This circuit is located in the burn scar area of the Lidia Fire in January 2025.

Risk Ranking	Circuit, Segment, or Span ID	Overall Utility Risk Score per HFRA Mile	Wildfire Risk Score per HFRA Mile	Outage Program Risk Score per HFRA Mile	Top Risk Contributors	Total Miles	Version of Risk Model Used
26	NUTMEG	0.09911	0.09911	0.00001	EFF Risk, CFO Other Risk	7.77	POI 2024, FireSight 8
27	SCHMIDT	0.09403	0.09403	0.00000	EFF Risk, CFO Other Risk	15.38	POI 2024, FireSight 8
28	SEAWOLF	0.09357	0.09357	0.00002	EFF Risk, CFO Other Risk	1.00	POI 2024, FireSight 8
29	ARAPAHO	0.09293	0.09293	0.00000	EFF Risk, CFO Other Risk	15.63	POI 2024, FireSight 8
30	MOAB	0.08632	0.08632	0.00000	EFF Risk, CFO Other Risk	0.56	POI 2024, FireSight 8
31	LUISENO	0.08624	0.08624	0.00000	CFO Other Risk, EFF Risk	30.21	POI 2024, FireSight 8
32	BALLOON	0.08509	0.08509	0.00001	EFF Risk, CFO Other Risk	4.22	POI 2024, FireSight 8
33	BOUQUET	0.08490	0.08490	0.00000	EFF Risk, CFO Other Risk	24.70	POI 2024, FireSight 8
34	CALSPAR	0.08419	0.08418	0.00002	EFF Risk, CFO Other Risk	0.33	POI 2024, FireSight 8
35	BIG ROCK	0.08344	0.08343	0.00001	CFO Other Risk, EFF Risk	14.09	POI 2024, FireSight 8
36	STAR ROCK	0.08282	0.08282	0.00003	EFF Risk, CFO Other Risk	2.39	POI 2024, FireSight 8
37	KELLER	0.08162	0.08162	0.00003	EFF Risk, CFO Other Risk	1.07	POI 2024, FireSight 8
38	CORTESE	0.08079	0.08079	0.00000	EFF Risk, CFO Other Risk	2.14	POI 2024, FireSight 8
39	BOOTLEGGER	0.08071	0.08071	0.00000	EFF Risk, CFO Other Risk	79.92	POI 2024, FireSight 8
40	UTE	0.08052	0.08052	0.00000	EFF Risk, CFO Other Risk	1.00	POI 2024, FireSight 8
41	SOUTHRIDGE	0.08047	0.08046	0.00000	EFF Risk, CFO Other Risk	0.48	POI 2024, FireSight 8
42	MOCKINGBIRD	0.07965	0.07965	0.00000	EFF Risk, CFO Other Risk	7.07	POI 2024, FireSight 8
43	CORONITA	0.07950	0.07950	0.00009	EFF Risk, CFO Other Risk	0.45	POI 2024, FireSight 8
44	ATENTO	0.07787	0.07787	0.00001	EFF Risk, CFO Other Risk	26.65	POI 2024, FireSight 8
45	PAWNEE	0.07717	0.07717	0.00000	CFO Other Risk, EFF Risk	54.81	POI 2024, FireSight 8
46	INYO LUMBER	0.07639	0.07638	0.00001	EFF Risk, CFO Other Risk	3.17	POI 2024, FireSight 8
47	PARADISE	0.07572	0.07572	0.00000	EFF Risk, CFO Other Risk	14.82	POI 2024, FireSight 8
48	PERRIS	0.07541	0.07541	0.00002	EFF Risk, CFO Other Risk	3.36	POI 2024, FireSight 8
49	RAMSGATE	0.07502	0.07502	0.00002	EFF Risk, CFO Other Risk	0.91	POI 2024, FireSight 8

5.6 Quality Assurance and Quality Control

The electrical corporation must document the procedures it uses to confirm that the data collected and processed for its risk assessment are accurate and comprehensive.[39] This includes but is not limited to model, sensor, inspection, and risk event data used as part of the electrical corporation's WMP program. In this section of the WMP, the electrical corporation must describe the following:

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

5.6.1 Independent Review

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

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

Independent Reviews

SCE has provided updated independent review plans in response to Revision Notice Critical Issue RN-SCE-26-03. That response is replicated here for completeness.

SCE is currently in the process of obtaining third-party independent reviews of components of its wildfire risk models. These reviews will help validate existing features and identify opportunities for modeling enhancements to incorporate into future versions of the models.

Planned external independent review efforts are focused on two areas: (1) SCE's probability of failure models; and (2) elements of SCE's fire potential index, which include review of fire weather days, fire climate zones, and fuels. This work is at various stages and is anticipated to be completed by end of Q1 2026.

While these efforts cover portions of SCE's risk models, some model components not in scope may require supplementary efforts. For example, item (e) below – PEDS risk – is not currently in scope. SCE is evaluating options to incorporate this scope into existing external, independent review efforts. If this is not feasible, SCE will engage an independent third party during this WMP cycle to review this and other modeling components raised in this Remedy.
SCE will consider timing and scope of future independent reviews based on the results of these efforts. Considering the costs and resourcing requirements needed to support these reviews, SCE envisions future model reviews will be most helpful when aligned to significant model, process, and/or risk framework changes.

Below, SCE provides some additional context that will further inform independent reviews for the risk modeling components specifically identified in this Required Remedy.

a. Burn probability: As described in Section 5 of its 2026-2028 WMP, SCE notes that Burn Probability components are typically used in conjunction with stochastic models (e.g., U.S. Forest Service model), rather than the deterministic models used by most California utilities. Given that this is a required component, for the purpose of completeness, SCE assumes a conditional burn probability of "1." in its deterministic model. SCE anticipates an external, independent review will also assess this approach that SCE has taken.

b. Fire Weather Days: As described in Section 5 of its 2026-2028 WMP, the selection of Fire Weather Days (FWDs) is an important input into SCE's deterministic wildfire model. FWDs represent the live and dead fuel moisture, wind (intensity, speed, direction), and other critical weather attributes present at the time of the simulated deterministic wildfire ignition events. SCE anticipates an independent review will evaluate SCE's approach to selecting FWDs.

c. Fire Climate Zones (FCZs): As described in Section 5 of its 2026-2028 WMP, SCE divided its service territory into Fire Climate Zones (FCZ), which are sub-regions of SCE's service territory with similar terrain, fuels, weather, and fire activity. The designation of FCZs is a critical component of SCE's overall risk modeling approach, as these regions are used to guide FWD selection and PSPS thresholds for different parts of SCE's service territory.
SCE anticipates an independent review will assess the criteria for defining FCZs and how these zones are used in the risk calculation. This may also include assessing topographic, vegetative, and other variables, as well as the fire regimes that influence wildfire risk in each area.

d. Custom Fuels and Fuel Adjustment Processes: As described in Section 5 of its 2026-2028 WMP, in addition to the traditional Scott and Burgan 40 (Scott and Burgan 2005) commonly used in deterministic wildfire risk models, SCE has supplemented its models with 19 custom fuel models to better represent recent industry science around wildfire modeling. This information includes the creation of new models to replace existing Scott and Burgan fuels based on several seasons of calibration with CalFire FireGuard data, as well as the creation of new fuel models to better represent how wildfires progress adjacent to urban areas. SCE anticipates an independent review will evaluate how these new custom fuels were created and the impact the adjustments have.

e. Incorporation of PEDs Risk: As described in Section 5 of its 2026-2028 WMP, and in accordance with new OEIS guidelines to assess Protective Equipment Device Settings (PEDS) risk, SCE developed a new risk model to incorporate PEDs as an Outage Risk, sub-model. SCE anticipates an independent third-party review will assess how this approach appropriately captures the risk impact, including a review of model assumptions, data used, and interaction with other risk components.

f. Other Components: In addition to the specific items listed above, SCE will define the independent reviewer's scope to have some flexibility to include other necessary assessments of SCE's risk models. Additional component reviews will be considered within the context of whether SCE has a reasonable amount of time to integrate recommendations into its current wildfire risk model development cycle. Throughout this review process, SCE will provide the independent reviewer(s) with access to model documentation, academic papers, and relevant OEIS and CPUC risk modeling guidelines. SCE will support the independent reviewer(s) in accessing relevant non-proprietary vendor documentation and relevant subject matter experts.

Where possible, SCE intends to explore opportunities to leverage contracts from existing engagements with qualified independent reviewers to conduct similar evaluations. SCE anticipates independent reviews originating from these existing engagements to be completed by the end of Q1 2026, which would include a review of components of SCE's probability of failure models and fire potential index. Further, SCE will assess the feasibility of issuing change orders or contract amendments with independent reviewers to reduce the lead time for review of other components where possible, while maintaining its integrity and independence. In these cases, SCE anticipates independent reviews to be completed in 2026, where feasible. In instances where new contracts must be established through competitive processes, SCE will seek to commence those contracting efforts in 2026. In all cases, SCE will provide updates on these efforts in future WMP filings.

Please see Appendix D of SCE's Revision Notice response for summary documents used to solicit third-party independent reviewers. SCE will provide updates on the results of this work in future WMP submissions.

Data Collection Review Activities

SCE has an extensive inspection program that is described in Section 8.3. Results from these inspections are validated and integrated into SCE's risk models in several ways. If the inspection identifies a discrepancy between what is observed in the field and what is recorded in SCE's databases (primarily SAP), SCE will update the information. Repairs and remediations that result from inspections are also integrated into SCE's asset database and, depending on the nature of the data, may be used in calculations such as POI. SCE's QA/QC programs, described in Section 8.5, provide assurance on the quality of the inspections themselves.

As discussed in Section 8.4 and 12.2, SCE analyzes ignitions through its Fire Investigation Preliminary Assessment (FIPA) program. Data and results from these analyses are used as both a data source for modeling and for trend analyses. The FIPA process supports data quality standards through applying consistent methodology and classifications to improve SCE's ability to use ignition data for wildfire risk analysis.

Data Input Review Activities

To prepare and organize its data for its risk models, SCE uses a combination of automated and manual checks of its data. SCE uses automated scripts to validate that unique data are not duplicative, data does not have nonstandard values, and checks for excessive null values. SCE also performs manual validation of the data set by comparing the current data set to previous data sets to check for discrepancies, using a Sankey diagram[77] to display the data flows, and appending data from alternative sources if data is missing.

Validation of Risk Models for Transmission Assets

In 2022, SCE began developing a more formal validation process of its risk models for transmission using field input. The validation compared assets that the SCE risk model identified as risky against assets identified as risky by the Transmission Senior Patrolman. Any variance between the two assessments were further analyzed for the cause of the difference in the result. SCE would then update its data or risk model as needed.

Another avenue to facilitate risk model validation is included in the Transmission survey that is completed during the high-fire risk informed (HFRI) detailed inspection. SCE includes a set of questions to allow the inspector to provide information if they support or disagree with the riskiness of the asset being inspected. This feedback is available to SCE to review and assess if an update to the risk models is needed. In 2023, SCE began including a similar set of risk assessment questions in the Distribution HFRI detailed inspection survey form to allow the inspectors to provide feedback.

Asset Risk Governance Working Team

SCE's Asset Risk Governance Working Team (ARGWT) provides oversight on risk identification, quantification, and mitigation of risk models. The ARGWT is responsible for evaluating issues related to asset risks and makes recommendations to the sponsor team. The recommendations of the working team consider the specific safety, reliability, and financial impacts of each risk model as appropriate to the relevant risk. As issues requiring asset risk management arise, the working team helps to organize an initiative team that may include subject matter experts from across SCE.

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77 A Sankey diagram is a visualization tool that shows how data or variables flow between sources or databases.

Additional Review Triggers

SCE's internal Enterprise Risk Management (ERM) team provides oversight for risk modeling more broadly. ERM is responsible for ensuring the ARGWT is providing recommendations to the sponsor team that are consistent and defendable, while using risk-based analysis where appropriate and practical.

ERM, along with SCE's Audit Service Department (ASD), provides recommendations to the ARGWT as to when additional third-party review is warranted. These recommendations may be based on the technical complexity of the subject matter or at the request of SCE management or other external stakeholders. Generally, given that the intent of these third-party reviews is to foster model improvement, the results of these reviews are kept confidential until their recommendations can be reviewed and implemented.

Results, Recommendations, and Disposition

SCE discusses the results and recommendations of the third-party independent evaluator's review of its RSE results in ACI SCE-22-22 Third Party Confirmation of RSE Estimates in Appendix D: Areas for Continued Improvement.

After SCE's third-party consultant reviewed its technical documentation for its risk models, the third- party consultant provided feedback on compliance with OEIS guidelines and new standardized documentation templates in alignment with OEIS guidelines, which includes model specification, sensitivity testing, benchmarking and data and input quality. These templates are used to support detailed documentation in Appendix B: Supporting Documentation for Risk Methodology and Assessment. SCE uses and updates these documentation templates for its risk models, including modeling, validation, and processes.

Routine Review Schedule

SCE currently does not have a routine third-party review schedule.

5.6.2 Model Controls, Design, and Review

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

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

- ***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*
    - *Equipment failure*
    - *Exposure and vulnerability analysis*
- ***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 it conforms to industry standard practices in version controlling its risk model and sub-models. At a minimum, the electrical corporation must report on:*
    - *Models and software version controls aligned with industry standard programs, procedures, and protocols.*
    - *Version control of model input data, including geospatial data layers.*
    - *Procedures for updating technical, verification, and validation documentation.*

Modularization

SCE's models are designed to be modular so that SCE can track and change inputs within the model. Table SCE 5-04 provides a summary of which models contain separate modules for the attributes identified.

Table SCE 5-04: Risk Models Containing Separate Modules

	Probability of Ignition	Wildfire Consequence (Technosylva)
Weather Analysis	No. Weather variables are not contained in a separate module for this model. Weather variables are attributes within the machine learning model.	Yes. Weather scenarios are modular in this model.
Fire Behavior Analysis	Not applicable, this model does not analyze or consider this element.	Yes. Fire Behavior Analysis is modular in this model.
Seasonal Vegetation Analysis	No. Vegetation variables are not contained in a separate module, they are attributes within the model.	Yes. Vegetation (i.e., fuel and fuel moisture) is modular in this model.
Equipment Failure	No. Equipment variables are not contained in a separate module for this model. They are attributes within the machine learning model.	Not applicable, this model does not analyze or consider this element.
Exposure and Vulnerability Analysis	Not applicable, this model does not analyze or consider this element.	Yes. HFRA (exposure) and AFN/NRCI (vulnerability) are separate components of this model.

Reanalysis

SCE updates its risk analysis annually and can provide previous yearly scenario runs as needed. Iterations of the risk model are reanalyzed with each refresh of the likelihood or consequence models as data becomes available. Outputs of these models are archived by date but are not intended to produce POI risk estimates for a specific historic date. The Wildfire Consequence model and IWMS analysis is limited to the FWD selected within the current model.

Version Control

Table SCE 5-05: Version Control

Models and software version controls aligned with industry standard programs, procedures, and protocols	
Probability of Ignition	Yes. SCE maintains documentation and model information changes as new assets and features are updated in the model. Code commentary is updated as versions are changed.
Wildfire Consequence	Yes. SCE's vendor maintains documentation and model information consistent with Energy Safety's guidelines.
Version control of model input data, including geospatial data layers	
Probability of Ignition	Yes. SCE reassesses and maintains POI models on an annual basis.
Wildfire Consequence	Yes. SCE reassesses and maintains wildfire consequence models on an biennial basis.
Procedures for updating technical, verification, and validation documentation	
Probability of Ignition	SCE maintains documentation detailing changes, enhancements, and improvements made to our POI model, pursuant to its goals in RM-1. SCE is in the process of updating its documentation and is evaluating various standards to utilize to further refine and standardize our documentation.
Wildfire Consequence	Yes. SCE's vendor maintains this information consistent with industry standard practice.

5.7 Risk Assessment Improvement Plan

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

- ***Risk assessment methodology:*** *Wildfire and PSPS risk assessment methodology and its documentation, including both quantitative and qualitative approaches.*

- ***Design basis:*** *Justification of design basis scenarios used to evaluate the risk and its documentation.*

- ***Risk presentation:*** *Presentation of risk to stakeholders, including dashboards and statistical assessments.*

- ***Risk event tracking:*** *Tracking and reconstruction of risk events and integration of lessons learned.*

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

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

Table 5-6 provides an example of the minimum acceptable level of information.

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

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

Table 5-6: SCE Risk Assessment Improvement Plan

Key Risk Assessment Area	Proposed Improvement	Type of Improvement	Expected Value Add	Timeframe and Key Milestones
RA-1, risk assessment methodology	Reassess fire spread modeling	Technical and programmatic	Mitigation scoping and potentially develop new mitigations	To be completed in 2025; pending results, any implementation planned 2026-2027
RA-1, risk assessment methodology	Explore the inclusion of additional wildfire impacts	Technical	Represent additional impacts of wildfire events, such as more accurate representation of building consequences	2026
RA-1, risk assessment methodology	Revise Elevated Wildfire Risk Designation – Informs Proposed HFTD Update submitted to the CPUC	Technical and programmatic	Update HFTD boundary to reflect contemporary data and understanding of elevated wildfire risk	SCE has submitted its proposal to the CPUC and is awaiting a schedule for the proceeding
RA-2, design basis	Develop Forward Looking Climate Change Scenario	Technical	Improve understanding of wildfire risk under future conditions	To be completed in 2025; pending results, any implementation planned 2026-2027
RA-3, risk presentation	Enhance WMP Risk Presentation dashboard	Technical	Automate dashboard calculations on a scheduled basis when new data becomes available.	As needed
RA-4, risk event tracking	Update Risk Events Database	Technical and programmatic	Identify broader trends and potentially allow SCE to propose mitigations to address potential issues before risk events occur	Daily

Reassess Fire Spread Modeling

- Problem statement: The January 2025 wildfires raise important questions regarding the spread of wildfires into built urban environments. Considering these questions, SCE will evaluate if changes to its wildfire risk models are warranted.
- Planned improvement: N/A at this time.
- Anticipated benefit: Improved understanding of wildfire spread into built urban environments.
- Region prioritization: Wildland Urban Interface (WUI) locations
- Supporting documentation (as necessary): N/A at this time.

Explore the inclusion of additional wildfire impacts

- Problem statement: SCE is assessing additional impacts of wildfire events (e.g., broader macro-economic impacts) and the potential benefit of using these impacts to inform activity selection and prioritization.
- Planned improvement: SCE is reviewing the available literature and exploring several options to integrate this type of information into its future wildfire risk modeling. SCE will provide updates in its 2027 WMP (Update) concurrent with its 2026 RAMP filing.
- Anticipated benefit: Better represent the potential impacts of wildfire events, particularly large events, which have a broader societal impact.
- Region prioritization: Entire SCE service territory.
- Supporting documentation (as necessary): N/A at this time.

Explore the inclusion of additional wildfire impacts

- Problem statement: SCE is assessing how Building Loss Factor (BLF) estimates can be used to differentiate building impacts between those buildings destroyed versus those buildings damaged during wildfire events.
- Planned improvement: SCE is reviewing the available literature and exploring several options to integrate this type of information into its future wildfire risk modeling. SCE will provide updates in its 2027 WMP (Update) concurrent with its 2026 RAMP filing.
- Anticipated benefit: Better represent the potential impacts of wildfire events, particularly events which impact built up urban environments.
- Region prioritization: Entire SCE service territory.
- Supporting documentation (as necessary): See Section 5.2.2.2.2.6 Building Loss Factor (BLF)

Revise Elevated Wildfire Risk Designation – Informs Proposed HFTD Update submitted to the CPUC

- Problem statement: Contemporary data and experience in wildfire mitigation have changed our understanding of which areas constitute elevated wildfire risk since SCE's 2019 report proposing updates the HFTD implemented.

- Planned improvement: SCE revised and executed upon its methodology for designating elevated wildfire risk from 2022 until 2024 with positive reception for the approach when presented to regulatory stakeholders including CPUC, CAL FIRE, MGRA, and Cal Advocates.[78]
- Anticipated benefit:
    - Net Reduction in Customer Costs: If proposed HFTD updates are accepted, aligned expenditure on mitigations with our understanding of wildfire risk, reduced due to urban areas proposed to be removed from HFTD.
    - Demonstration of continued improvement in updating HFTD to reflect changing conditions and current risk analysis
- Region prioritization: SCE Service Territory
- Supporting documentation (as necessary): SCE's (U 338-E) Petition for Modification of Decision 17-12-024 to Update HFTD Boundaries in its Service Territory and Appendices, dated November 8th, 2024, available on www.sce.com/wmp

Develop Forward Looking Climate Change Scenario

- Problem statement: In the context of its 2026 RAMP filing, SCE is required to file a Climate Change Pilot. As part of this pilot, SCE is assessing how climate change may impact the frequency of Fire Behavior Outcomes (FBOs), as well as any changes in the consequences of wildfire risk events based on a forward-looking climate change scenario.
- Planned improvement: Simulate forward looking weather and fuels to determine how frequency of fire weather, as well as resulting consequences, may change over time.
- Anticipated benefit: Provide understanding of how wildfire risk may increase in SCEs service territory over time. This information will be used to inform wildfire and PSPS mitigation selection and deployment, particularly for mitigations with long effective useful lives (EULs).
- Region prioritization: Entire SCE Service Territory
- Supporting documentation (as necessary): See Section 3.7 and 5.3 for additional information.

Enhance WMP Risk Presentation dashboard

- Problem statement: Information about activities' mitigation effectiveness, scope, and spend was decentralized across the organization, making it difficult to gain insight into risk spend efficiency calculations.
- Planned improvement: Automate dashboard calculations on a scheduled basis when new data becomes available.
- Anticipated benefit: Understand the different components that make up a Risk Spend Efficiency score and the associated trends in the data.
- Region prioritization: HFRA.
- Supporting documentation (as necessary): Risk presentation dashboard.

78 See Section 5.5.1.2 Proposed Updates to the HFTD for detail on SCE's process for requesting updates from the CPUC.

Update Risk Events Database

- Problem statement: Disparate systems with information on events such as failures, ignitions, and wire-downs and reliance on subject matter experts to gather and interpret trends.
- Planned improvement: SCE implemented its risk event platform in 2024. The improvement is to identify broader trends and improve collection of event information.
- Anticipated benefit: Enable a meaningful analysis of trends and risk events and develop appropriate mitigations.
- Region prioritization: Entire service territory.
- Supporting documentation (as necessary): Risk event database.

6 WILDFIRE MITIGATION STRATEGY

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

6.1 Risk Evaluation

6.1.1 Approach

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

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

As described in Section 5, SCE utilizes its Integrated Wildfire Mitigation Strategy (IWMS) Risk Framework to categorize locations in SCE High-Fire Risk Areas (HFRA) into one of three categories: Severe Risk Areas (SRA), High Consequence Area (HCA), and Other HFRA. These categories are used in conjunction with SCE's Multi-Attribute Risk Score (MARS) framework to prioritize mitigation deployment. SCE's approach is consistent with industry best practice and has been extensively discussed in the OEIS-led risk working group as well as the Rulemaking to Further Develop a Risk-Based Decision-Making Framework[79] at the Commission.

After the overhead asset has been assigned an IWMS category and assigned a risk score with the MARS framework, SCE then designs an appropriate mitigation portfolio to address the full range of sub drivers, and other risk factors present in that location.

While mitigation selection is carefully tailored to each location, SCE has developed a series of mitigation packages comprised of a portfolio of complementary mitigations for each IWMS category tailored to specific risk levels identified in each location,[80] namely:

- SRA - SCE has determined that for public safety reasons it is prudent to minimize risk in the long term to the extent practicable given the significant threat to lives and property.
- HCA - SCE's strategy in these locations focuses on mitigating ignition risk drivers, as well as minimizing PSPS impacts.
- Other HFRA - SCE will replace retired or damaged bare wires with covered conductors and continue mitigations with relatively low incremental costs that are dictated by compliance requirements or are prudent based on local conditions.

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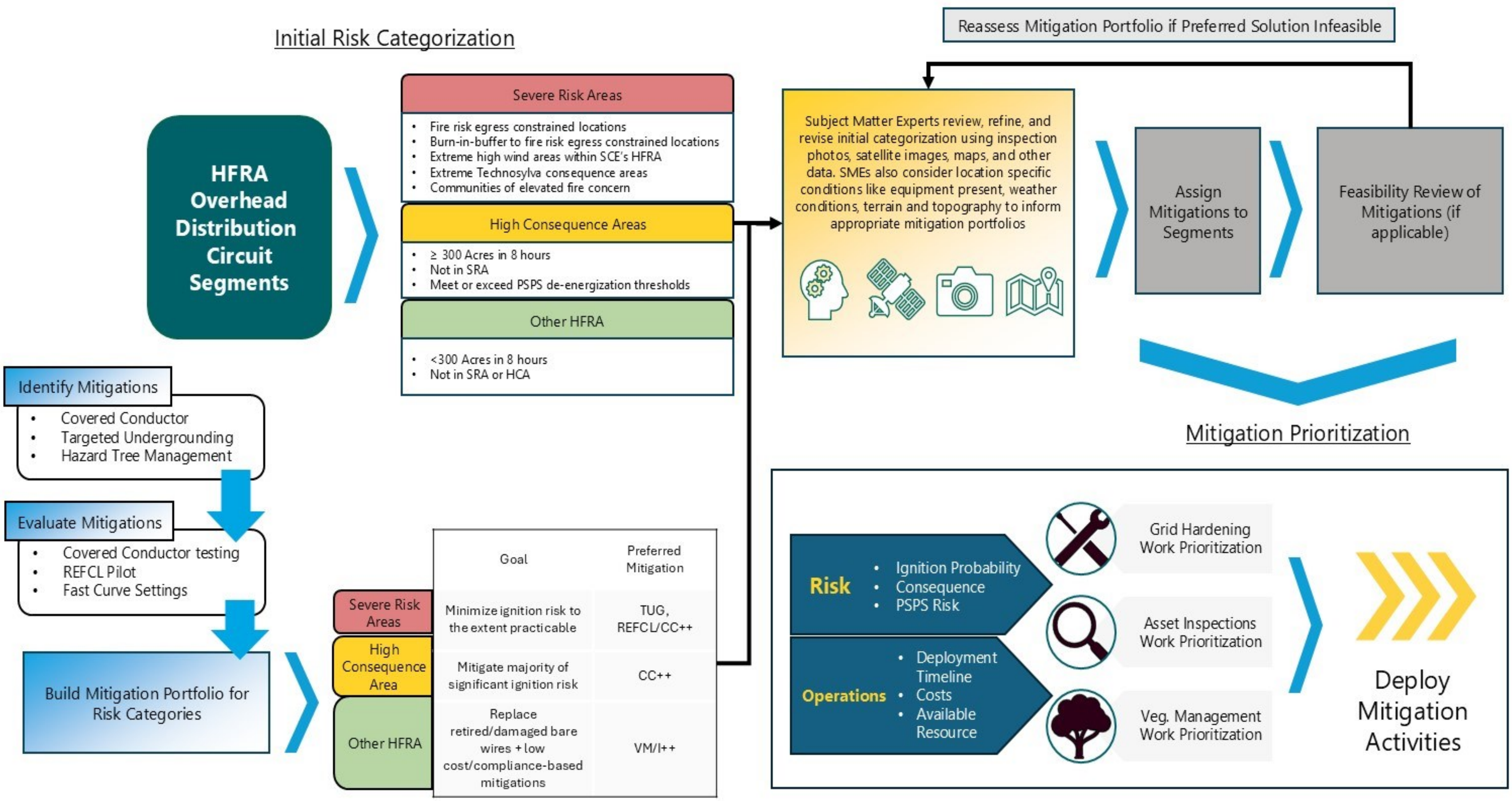
79 R.20-07-013.

80 Overhead transmission assets in SCE's HFRA contain different risk profiles than distribution asset. In such, these assets are subject to a different set of mitigation selection criteria.

Once mitigation packages are assigned to specific locations, mitigation selection, design, and deployment are tailored to each location based on environment and operational factors, as well as authorized CPUC funding levels. Generally, SCE attempts to use complementary mitigations to address risk drivers as individual locations. In many cases, these complementary mitigations may use different resources. For instance, grid hardening mitigations (e.g., covered conductor (CC) or targeted undergrounding (TUG)) use different resources than maintenance, inspection, or vegetation management activities. In many cases, these mitigations can be deployed in parallel (e.g., inspections and grid hardening). In other cases, the timelines for their deployment may be vastly different (e.g., TUG and CC projects have long timelines, whereas fast-acting fuses may be deployed in a shorter timeframe).

In sum, SCE identifies the varying levels of wildfire and PSPS risk in its HFRA and then deploys complementary and cost-effective portfolios of mitigations that are prioritized in a risk-informed manner. Please see Figure SCE 6-01 for a high-level schematic of this process.

Figure SCE 6-01: IWMS Mitigation Selection and Deployment Process



6.1.2 Risk-Informed Prioritization

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

In this section, the electrical corporation must:

- *Describe how it selects circuit segments of its service territory at risk from wildfire for potential activities, including, at a minimum, the following:*
    - *Geographic scale used in prioritization (i.e., regional, circuit, circuit segment, span, asset)*
    - *Statistical approach used to select prioritized areas (e.g., circuit segments in top 20 percent for risk, circuit segments in top 20 percent for consequences)*
    - *Feasibility constraints (e.g., limitations on data resolution, jurisdictional considerations, accessibility)*
- *Present a list that identifies, describes, and prioritizes circuit segments of its service territory at risk from wildfire for potential activities based solely on overall utility risk, including the associated risk drivers. Associated risk drivers must be ranked in order of most impactful to risk.*

Examples of the minimum acceptable level of information and the required format are provided in Table 6-1

Geographic scale used in prioritization (i.e., regional, circuit, circuit segment, span, asset)

The scale used in SCE's prioritization of activities is dependent on the activity being modeled. For example, at one end of the spectrum, when prioritizing asset inspections, SCE prioritizes at the structure level. At the other end of the spectrum, when prioritizing locations for Rapid Earth Fault Current Limiter (REFCL) Ground Fault Neutralizers (GFNs), SCE prioritizes at the substation level. For certain grid hardening activities like CC or TUG, SCE generally prioritizes at the isolatable circuit segment level. As such, SCE uses a variety of levels of scale when prioritizing wildfire mitigation activities.

Statistical approach used to select prioritized areas

SCE's definition and selection of areas for prioritization is not defined from the perspective of a "top X" percentage of risk. As described in Chapter 5, SCE uses its IWMS framework in conjunction with its MARS framework to prioritize areas of its system on which to mitigate risk. SRA (approximately 30% of HFRA) presents the greatest consequence risk to public safety, followed by HCA (approximately 45%), and then Other HFRA (approximately 25%).

Feasibility constraints

The order in which SCE deploys its activities, while risk-informed, is also influenced by factors such as permitting, land rights, equipment availability, and accessibility issues. Permitting issues can take months or even years to resolve with agencies. Researching land rights and negotiating with landowners can also take a considerable amount of time. For certain activities that require highly specialized equipment, such as REFCL, timelines are often affected by vendor capabilities. Accessibility issues, such as those caused by snow or nesting bird season, will often delay projects. SCE mitigates these issues by executing activities in other high-risk locations concurrently and deploying interim activity measures to mitigate risk while the long-lead time activity is completed.

List of prioritized areas

Table 6-1 (below) is a list of isolatable circuit segments in SCE's service territory prioritized for activity deployment based on overall utility risk, as well as the presence of associated risk drivers.

Table 6-1: List of Prioritized Areas in SCE's Service Territory Based on Overall Utility Risk[81,82]

Priority	Circuit Segment and/or Span ID	Length (miles)	Overall Utility Risk	Wildfire Risk	Outage Program Risk	Percent of Overall Utility Risk	Associated Risk Drivers
1	SHOVEL_RAR0419_EOL	25.43	4.0312	4.0312	0.0000	1.51%	CFO Other Risk, EFF Risk
2	SHOVEL_RAR0102_RCS0621	8.09	2.5774	2.5774	0.0000	0.97%	CFO Other Risk, EFF Risk
3	FINGAL_CB_RAR0352	13.67	2.4849	2.4849	0.0001	0.93%	EFF Risk, CFO Other Risk
4	DAVENPORT_RAR0051_EOL	8.19	2.4553	2.4552	0.0000	0.92%	EFF Risk, CFO Other Risk
5	DAVENPORT_RAR0050_RAR0586	9.40	2.4027	2.4027	0.0000	0.90%	EFF Risk, CFO Other Risk
6	HUGHES LAKE_RAR0442_EOL	22.94	2.3169	2.3169	0.0000	0.87%	EFF Risk, CFO Other Risk

81 Due to the large volume of data, SCE is only presenting information for the top 20 isolatable circuit segments prioritized by overall utility risk in this filing. Additional circuit segment information may be found in the excel version of this table.

82 Risk scores as of 3/20/2025 calculated via the MARS Framework. Values for Overall Utility Risk Score, Wildfire Risk Score, and Outage Program Risk Score represent average MARS value per circuit mile within HFRA. Top Risk Contributors indicates the top two risk drivers (listed in order). SCE updated this table on 3/20/2025.

Priority	Circuit Segment and/or Span ID	Length (miles)	Overall Utility Risk	Wildfire Risk	Outage Program Risk	Percent of Overall Utility Risk	Associated Risk Drivers
7	PASCAL_RAR1915_EOL	9.86	2.2616	2.2616	0.0001	0.85%	EFF Risk, CFO Other Risk
8	POPPET FLATS_CB_RAR0980	14.38	2.1826	2.1825	0.0001	0.82%	EFF Risk, CFO Other Risk
9	STONEMAN_CB_RCS7996	11.77	2.1496	2.1496	0.0001	0.81%	EFF Risk, CFO Other Risk
10	KICKAPOO TRAIL_RCS0908_EOL	30.50	2.0757	2.0757	0.0001	0.78%	EFF Risk, CFO Other Risk
11	PHEASANT_CB_RAR0687	3.10	2.0420	2.0420	0.0000	0.77%	EFF Risk, CFO Other Risk
12	DAVENPORT_RAR3480_RAR0050_RAR0051_	12.23	2.0124	2.0124	0.0000	0.76%	EFF Risk, CFO Other Risk
13	DAVENPORT_RAR0173_EOL	11.38	1.9436	1.9436	0.0000	0.73%	EFF Risk, CFO Other Risk
14	SOPHIE_CB_EOL	24.42	1.9416	1.9416	0.0000	0.73%	EFF Risk, CFO Other Risk

Priority	Circuit Segment and/or Span ID	Length (miles)	Overall Utility Risk	Wildfire Risk	Outage Program Risk	Percent of Overall Utility Risk	Associated Risk Drivers
15	BOOTLEGGER_RAR7203_RAR7134_PS0293_	13.59	1.8682	1.8682	0.0000	0.70%	CFO Other Risk, EFF Risk
16	WINERY_RAR1690_RAR1360	29.83	1.8485	1.8485	0.0000	0.69%	CFO Other Risk, EFF Risk
17	POPPET FLATS_RAR0980_EOL	15.91	1.8224	1.8224	0.0001	0.68%	EFF Risk, CFO Other Risk
18	LUISENO_RAR1971_EOL	13.01	1.7726	1.7726	0.0000	0.67%	CFO Other Risk, EFF Risk
19	STORES_RAR1072_RAR1024_RAR0820_	7.59	1.7529	1.7529	0.0000	0.66%	EFF Risk, CFO Other Risk
20	RAYBURN_PS2219_EOL	4.96	1.6993	1.6993	0.0000	0.64%	EFF Risk, CFO Other Risk
Please see www.sce.com/wmp for the full list in Excel format.							

6.1.3 Activity Selection Process

After the electrical corporation creates a list of top-risk contributing circuits/segments/spans (Section 5.5.2) and prioritized circuit segments based on overall utility risk (Section 6.1.2), the electrical corporation must then identify potential mitigation strategies. It must also evaluate the benefits and drawbacks of each strategy at different scales of application (e.g., circuit, circuit segment, system-wide). In this section of the WMP, the electrical corporation must provide the basis for its decisions regarding which activities to pursue. The electrical corporation must consider appropriate activities depending on the local conditions, physical setting, and the risk components that create the high-risk conditions. There may be a wide variety of potential activities, such as:

- *Engineering changes to grid design*
- *Discretionary inspection and/or maintenance of existing assets*
- *Vegetation clearances beyond minimum regulatory requirements*
- *Alternative operational policies, practices, and procedures*
- *Improved emergency planning and coordination*

The electrical corporation must also evaluate mitigating risk through a portfolio of combined multiple activities.

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

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

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

SCE designs portfolios of mitigations that complement each other and mitigate multiple risk drivers. This process begins with the mitigation intake process, where SCE uses MARS to evaluate effectiveness and alternatives to each prospective mitigation. SCE then takes a holistic approach to developing complementary activities that address risk drivers based on risk analysis, historical ignition trends or findings, and expert review. SCE also considers cost-effectiveness, how quickly the mitigations can be deployed, and deployment feasibility based on terrain and other factors. After SCE understands the relative effectiveness of each mitigation as well as the drivers it addresses, SCE designs portfolios of mitigations for each area of its system, commensurate with the area's assigned risk tranche.

6.1.3.1 Identifying and Evaluating Activities

The electrical corporation must describe how it identifies and evaluates options for mitigating wildfire and outage program risk at various analytical scales, consistent with the CPUC guidelines associated with the Risk-Based Decision-Making Framework (RDF) established in the RDF Proceeding.[83] *The electrical corporation must present the risk mitigation identification procedure it plans on using during the course of the three years filed in the Base WMP. If the electrical corporation is required to submit a RAMP filing to the CPUC, the risk mitigation procedure provided must be consistent with either its most recent RAMP filing or its upcoming RAMP filing. The electrical corporation must describe the following:*

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

83 The CPUC initially adopted its Risk-Based Decision-Making Framework in D.18-12-014 (see RDF, step 2, rows 15–25), https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M250/K281/250281848.pdf.
The CPUC updated its Risk-Based Decision-Making Framework in December 2022 in D.22-12-027, https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M500/K014/500014668.PDF and June 2024 in D.24-05-064 https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M533/K099/533099839.PDF. These Decisions changed the risk evaluation framework from Multi-Attribute Value Function (MAVF) to Cost-Benefit Analysis (CBA). The RDF builds on the requirements established in the Safety Model Assessment Proceeding (S-MAP, A.15-05-002) and the Risk-Based Decision-Making proceeding (R.13-11-006).

equipment settings versus undergrounding, secondary hardening, and asset inspections).

- *Estimated implementation costs*

  - *Where activities can be feasibly deployed in combination, the utility must compare these portfolios of activities (e.g., covered conductor, vegetation management, and protective device and equipment settings versus undergrounding and secondary hardening).*

- *Relevant uncertainties and associated potential impacts, including solutions on how to reduce the potential impacts*

- *Implementation schedule*

- *How the electrical corporation uses multi-attribute value functions (MAVFs), cost- benefit analysis (CBA), and/or other specific risk factors (as identified in relevant CPUC Decisions) in evaluating different activity alternatives.*

  - *This must include how the electrical corporation considers cost efficiencies when evaluating activities, including overlap with planned or projected upgrades due to future grid needs (e.g., load capacity, peak demand, system flexibility).*[84]

- *How the electrical corporation defines different aspects of risk considerations, including: Risk Scaling, Risk Tolerance, Uncertainty, and Tail Risk in its risk mitigation strategies.*[85]

  - *Must break out each by safety and reliability (PSPS and PEDS), as applicable*

  - *Must include a discussion of how each aspect impacts mitigation selection and prioritization*

Below, SCE provides a detailed flowchart of our risk-informed decision-making process used to select and evaluate SCE activities to mitigate wildfire and outage program risks. We also provide a detailed narrative explanation of various entries in, and aspects of, the flowchart. For ease of reading and reference, we provide a "zoom in" of the particular portion of the flowchart when we are explaining it in narrative form.

Broadly speaking, the process can be broken down into three major stages, as outlined in the flowchart: First, we evaluate or reassess, and then prioritize, wildfire and outage program risks. Second, we identify the potential activities to address the risk. In other words, we pinpoint the

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84 These considerations must be in alignment with the CPUC's Decision Adopting Improvements to Distribution Planning and Project Execution Process, Distribution Resource Planning Data Portals, and Integration Capacity Analysis Maps, D.24-10-030 and with the CPUC's Rulemaking to Modernize the Electric Grid for a High Distributed Energy Resources Future, R.21-06-017

85 D.24-05-064 at 35-48, 54-57, and 97-99. See also CPUC Assigned Commissioner's Phase 4 Scoping Memo and Ruling, September 13, 2024, at 3.

various activity alternatives. Third, we evaluate the activities and select the appropriate one(s) from among the alternatives, using decision-making factors.

Application of this process for each wildfire mitigation activity may vary because SCE is continually improving how risk-informed decision-making is used across the enterprise. Applicability may also vary depending on the unique characteristics of the activities. While specific processes and steps continue to evolve as we build out our wildfire mitigation capabilities, the flowchart generally captures the key elements of the process. With each cycle, SCE's risk-informed decision-making process generally is maturing in the level of quantitative analysis performed, granularity of analysis, and consistent application across the enterprise.

Figure SCE 6-02: Wildfire Mitigation Activity Selection Process

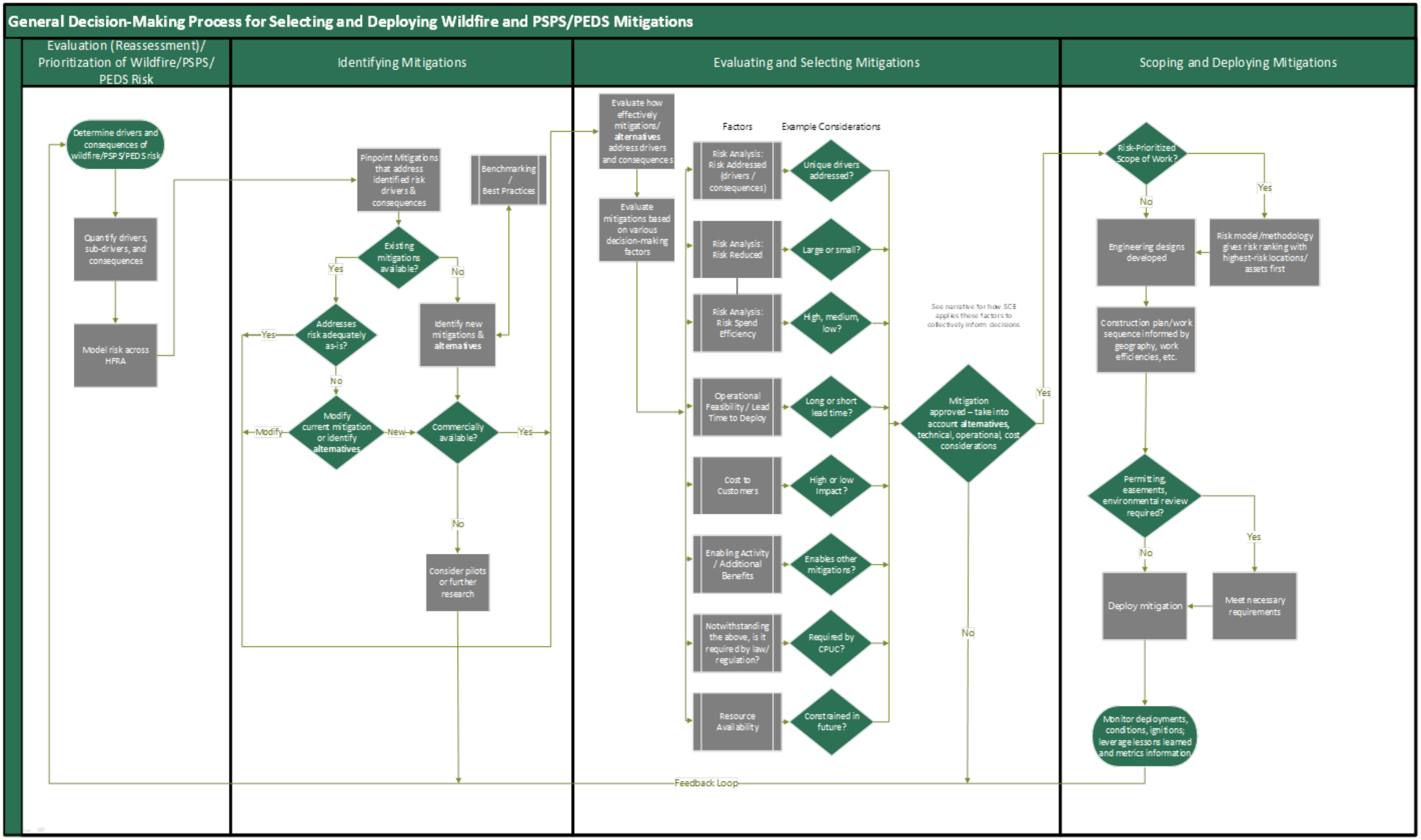
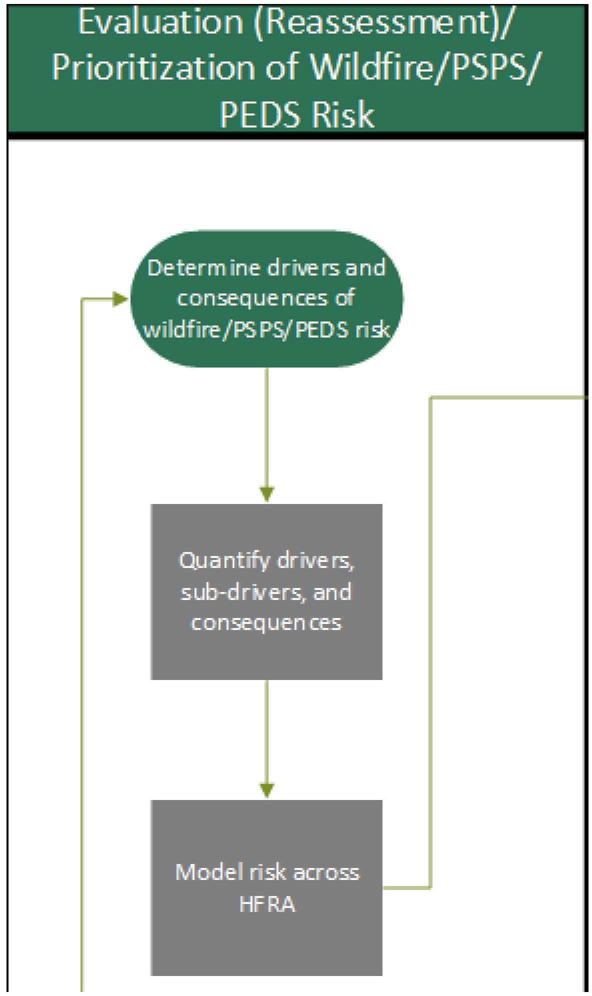


Figure SCE 6-03: Evaluation of Wildfire and Outage Program Risk (excerpt from full version in Figure SCE 6-02)



The process of selecting wildfire and outage program risk activities starts with evaluating or reassessing the particular issue at hand, and the risks associated with the issue. SCE has invested considerable resources to build its capabilities for identifying the drivers and consequences of wildfire and outage program risk and examining how that risk is distributed across SCE's HFRA. This is discussed in further detail in Section 5.2 but is summarized here for context. The general steps embedded in SCE's process for identifying and evaluating wildfire risk are as follows:

Determine drivers (and sub-drivers) and consequences of wildfire risk

As discussed in detail in Section 5, SCE applies the risk bowtie approach to enable us to consistently and systematically identify threats and characterize sources of risk.

Quantify drivers, sub-drivers, consequences, and overall risk as appropriate

The triggering event at the center of the wildfire bowtie is an ignition in SCE's HFRA. On the left-hand side of the bowtie, historical ignition and fault analysis determined that potential ignitions are primarily driven by equipment failure, contact from objects (such as vegetation or mylar balloons), and wire-to-wire contact (during periods of high winds). SCE leverages machine learning models to estimate the probability of ignition by driver for a given set of assets in HFRA.

The consequences of these ignition events are estimated on the right-hand side of the bowtie, using the Technosylva consequence model (starting in late 2020). The model estimates the potential spread of a fire over a given time, as well as the corresponding impact of a fire in natural units - structures, acres, and population.

The risk bowtie for PSPS risk evaluates the drivers and probabilities of PSPS activation. Here, SCE uses data points such as the historical back-cast of wind and weather conditions in conjunction with PSPS de-energization protocols to estimate the annual frequency and duration of de-energization events. The consequences of these PSPS events are estimated on the right-hand side of the bowtie, based on the potential safety, reliability, and financial impacts to customers.

The risk bowtie for Protective Equipment and Device Settings (PEDS) risk evaluates the drivers and probabilities of outages on fast curve-enabled circuits. SCE uses data points such as historical outages in conjunction with fast curve installation and operational data to estimate the annual frequency and duration of de-energization events. The consequences of these PEDS events are estimated on the right-hand side of the bowtie, based on the potential safety, reliability, and financial impacts to customers.

Model this risk across SCE's HFRA

As previously discussed in Section 5, SCE uses its IWMS framework to categorize locations in SCE HFRA into SRA, HCA or Other HFRA.

Consistent with the Risk-Based Decision-Making Framework, row 26 guidance, SCE uses its MARS Framework to translate Wildfire and outage program consequences into MARS units to compare the relative risk of wildfire ignitions/outage program events across SCE HFRA locations. The output of individual models and/or the entirety of the model output can be used to inform risk-related decision-making.

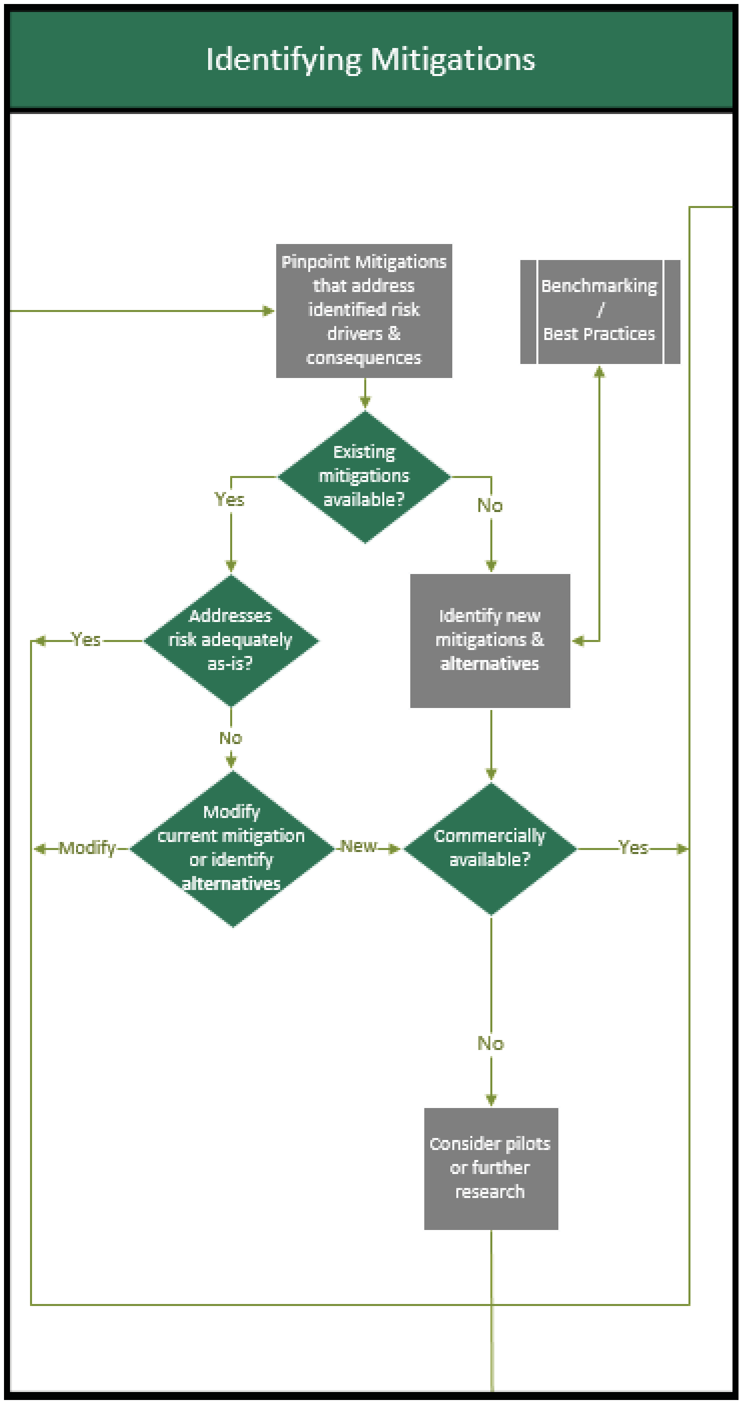
Currently the concepts of Risk Scaling/Attitude and Tolerance, as defined in phase 3 of the RDF OIR, are not used by SCE; however, SCE generally operates with risk aversion (as opposed to risk neutral or risk seeking) in regard to catastrophic wildfires. Similarly, SCE does not have a formal risk Tolerance,[86] but for SCE's riskiest areas (i.e., SRA), SCE has minimal risk tolerance.

As for Uncertainty, we currently look at the full range of potential consequences based on truncated 8-hour and 24-hour simulation times, across all fire weather data. See Section 5.2.2.2.2.2 charts.

For Tail Risk, although we look at a full range of potential outcomes, SCE uses maximum consequences to inform prioritization of mitigation deployment to the riskiest areas. In addition, SCE uses the additional qualitative factors from IWMS to complement the simulations in order consider a complete picture of risk.

86 SCE notes that the topic of Tolerance is particularly unsettled. SCE supports MGRA's proposal in the RDF proceeding to have a separate track to consider risk tolerance more directly.

Figure SCE 6-04: Identifying Mitigations (excerpt from full version in Figure SCE 6-02)



The second step in selecting wildfire and outage program risk activities is to identify candidate activities to mitigate wildfire and/or outage program risk. SCE focuses on potential options to reduce the risks that we evaluated or reassessed, and then prioritized, in the first step. These potential options come in the form of existing, modified, or new activities. Activity options reduce the frequency and/or consequence of wildfire and outage program risk, resulting in overall risk reduction. Activity options fall into one of four general categories, as described below:

Existing activities that already help to reduce risk

At times, the work that SCE performs to maintain and upgrade its overhead systems in HFRA already provides certain risk reduction benefits. In such cases, these activities would be identified for continued implementation as prudent for purposes of reducing wildfire risk. One example is line clearance activities to reduce the probability of faults or ignitions from vegetation contact with energized equipment.

Existing activities that, when modified, can further reduce risk

In other cases, existing mitigation activities may support wildfire risk reduction, but if appropriately modified, could provide even greater risk reduction benefits. This modification can take several forms:

- The scope of the activity could be modified. An example is expanding the scope of assets and asset conditions that are evaluated as part of an inspection program.
- The scale of the activity could be increased to cover a wider area of SCE's HFRA.
- The frequency of an activity could be modified. An example would be to increase how frequently critical or higher-risk assets or areas are inspected.
- New technology could be incorporated to make the activity more effective or efficient at identifying and mitigating risk. As an example, incorporating Artificial Intelligence/Machine Learning models to help detect asset defects and identify hazards as part of the Aerial Inspection processes could result in decreased time for problem identification, with increased confidence in risk/issue detection.

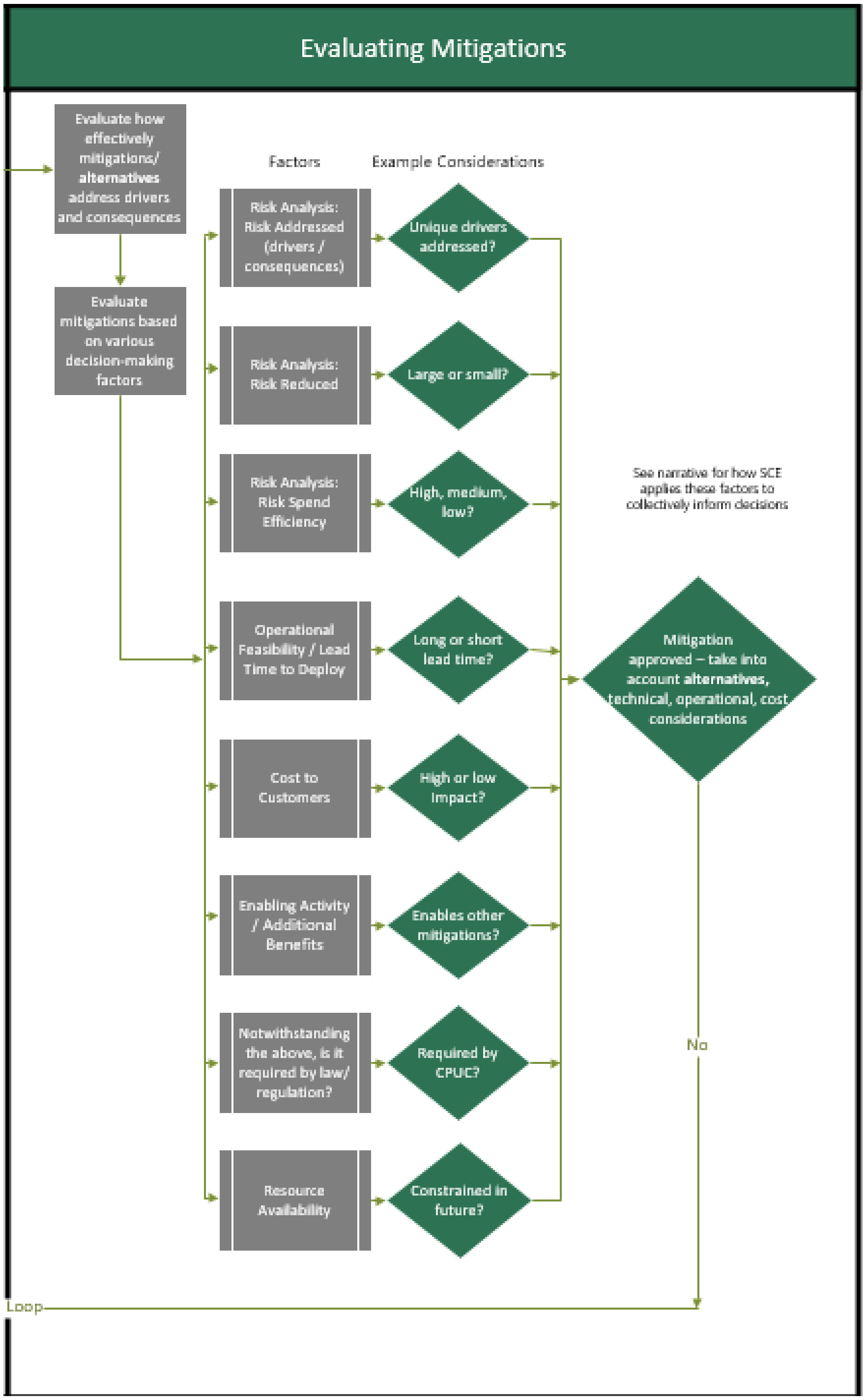
New activities that are commercially ready to deploy to reduce risk

SCE also identifies new risk mitigation options. These new options can be identified through efforts such as benchmarking with other utilities, studying and adopting emergent best practices, obtaining guidance from engineering and technical industry committees, studying emerging technology demonstrations, and assessing pilot studies that produce successful or otherwise useful results. SCE's portfolio of wildfire mitigation activities has benefitted from identifying and adding new activities that were not previously deployed in SCE's service territory. Our covered conductor program is an example of one such activity.

New activities that should be piloted and further evaluated for potential future deployment

In some cases, concepts emerge that have promising wildfire or outage program risk reduction benefits but have not yet been fully studied or evaluated through a reliable pilot or demonstration. Because these options are not commercially ready to be deployed on SCE's system, SCE will typically engage in further consideration of these options through a pilot project, demonstration effort, or smaller-scale field testing or pilot deployment. Technological maturity is an important criterion when identifying and assessing activities.

Figure SCE 6-05: Evaluating Activities (excerpt from full version in Figure SCE 6-02)



After identifying our potential risk mitigation options, we evaluate the options for deployment. This usually starts with an estimation of how effective each option can be in reducing the various wildfire and/or outage program risk drivers and consequences. Subject matter experts (SMEs) utilize engineering data, historical performance data, benchmarking information, research studies, results from demonstrations or field tests, and other sources of information to perform the analysis.

SCE is focused on efficiently reducing wildfire and outage program risk as quickly as reasonably possible, prioritizing activities in areas of our system that present the highest risk and doing so in a manner that appropriately minimizes customer cost and service impacts. Therefore, the selection of wildfire activities must consider several factors in the decision-making process including: the risk profile for HFRA in SCE's service territory; the risk profile of assets that have the potential to cause ignitions; how each activity affects the frequency and/or impact of wildfires; the potential speed of deployment; costs; Risk Spend Efficiency (RSE) scores; resource constraints; material or technology availability; and other factors that may relate to a given initiative.

Figure SCE 6-06 provides additional details concerning the key factors shown in the flowchart above that are commonly considered as part of SCE's decision-making process when selecting wildfire mitigation activities. The figure also illustrates how SCE generally evaluates each factor when making decisions.

Figure SCE 6-06: Decision-Making Factors Considered

		Features that can dissuade initiative selection	Features that can encourage initiative selection
Critical Factors that drive initiative selection	Risk Analysis - Risk Drivers and Consequences Addressed - Risk Reduced - RSE	Risk drivers and consequences not adequately addressed; Low magnitude of risk reduction; Low RSE	Many risk drivers and consequences addressed or only initiative to address specific risk-driver(s); High magnitude of wildfire and/or PSPS risk reduction; High RSE
	Operational Feasibility / Lead Time to Deployment	Limited or constrained ability to execute; Longer lead time than alternatives	No operational constraints; Shorter lead time than alternatives
Additional Critical Factors that supplement initiative selection decision	Cost to Customers	Higher cost impacts	Lower cost impacts
	Enabling Activity / Add'l Benefits	Does not enable other initiatives; Limited or no non-wildfire benefits (e.g. reliability)	Additional non-wildfire benefits; Necessary for the successful deployment of other initiatives
Overarching Factors that can drive absolute "Go/No-Go" selection decisions themselves	Compliance Requirements / Regulatory Guidance	N/A (Does not factor into selection)	Meet compliance requirements, aligns with regulatory guidance
	Resource Availability	Resource constraints prevent near-term implementation	Resources fully available to plan and execute work

SCE carefully considers each factor both individually and in the aggregate in order to make sound and informed decisions. A given factor may not have a uniform level of importance or impact in all situations. As an example, if an activity is required pursuant to a regulation, standard, code, or other authority, then meeting and adhering to compliance requirements would naturally be a decisive factor in SCE's ultimate determination. Similarly, if an activity is under consideration but SCE would be unable to sufficiently staff it with requisite resources, then the "Resource Availability" factor will more heavily influence our decision-making. This is because it may be infeasible to execute the activity in a timely manner. Below, SCE describes each decision-making factor in greater detail.

Risk Drivers and Consequences Addressed: There are many drivers to wildfire risk. It is necessary to have a portfolio of activities that collectively and sufficiently addresses the breadth of risk drivers.

In some cases, an activity such as covered conductor will address numerous risk drivers. In other cases, activities may narrowly – but importantly – address one risk driver that none of the other initiatives address. For example, SCE's transmission splice remediation initiative (SH-20) was included in SCE's WMP to address a very specific potential risk driver associated with transmission splice failures. In some cases, a mitigation activity addresses a key driver that is already addressed to some degree by other activities, but the configuration is beneficial because the multiple activities work together to address the driver better than any single mitigation activity. An example of this is that covered conductor addresses vegetation making contact with wires, but line clearance and Hazard Tree Management Program (HTMP) activities are also necessary to reduce heavy branches or trees from falling into lines that covered conductor may not be able to withstand. Moreover, vegetation management activities can be deployed more rapidly than covered conductor installation, and therefore can help reduce risk across HFRA in advance of covered conductor being installed. SCE's development of mitigation portfolios to address multiple risk drivers is discussed extensively in Section 6.1.3.2. Finally, SCE also evaluates activities based on their ability to mitigate risk consequences. As an example, SCE partners with fire agencies to deploy Aerial Suppression resources. These resources do not prevent wildfire events from occurring; instead, they help to alleviate the consequences of a wildfire event when it occurs.

Risk Reduction: SCE aims to expeditiously reduce as much as possible the risk of our electrical lines and equipment being involved in an ignition that can lead to a wildfire. As SCE evaluates wildfire activities, the magnitude of risk reduction is a central consideration, with a preference for activities that can provide higher risk reduction.

Table SCE 6-01 shows the relative effectiveness of wildfire mitigation programs for wildfire risk drivers and PSPS. In the table, a solid white ball indicates no effectiveness (0%) at the driver level, while a solid black ball indicates the highest degree of effectiveness (>75%) at the driver level. The Harvey Balls are based on the weighted average effectiveness values of each ignition subdriver applicable to the driver category and are biased against historical recorded ignition drivers. For example, an activity can be effective against an ignition driver, but because there have been zero historical ignitions related to that particular ignition driver, its weighted effectiveness is zero.

Note that the Contact from Object driver was split into two categories: "Contact from Object – Vegetation" which represents effectiveness against vegetation contact and "Contact from Object – Other" which represents effectiveness against contact with another item, such as an animal, balloon, or vehicle.

The impact of PEDS is generally much lower than the impact of PSPS. In the table, PSPS and PEDS effectiveness, respectively, are categorized as High, Medium, or Low. High indicates that the mitigation will result in a significant reduction or complete elimination of PSPS/PEDS, whereas Low indicates a limited reduction of PSPS/PEDS.

Table SCE 6-01: Mitigation Effectiveness

Tracking ID	Activity	Contact from Object - Veg.	Contact from Object - Other	Wire-to-wire contact	Equipment Failure[2]	Other	PSPS	PEDS
SH-1[1]	Covered Conductor	◕	●	●	◑	○	Medium	Medium
SH-2	Undergrounding Overhead Conductor	●	●	●	●	●	High	High
SH-5	Remote Controlled Automatic Reclosers	N/A	N/A	N/A	N/A	N/A	Low	N/A
SH-14	Long Span Initiative (LSI)	◔	◔	●	◔	○	N/A	N/A
SH-17	Rapid Earth Fault Current Limiters (REFCL) - Ground Fault Neutralizer	◑	◑	○	◑	◑	N/A	N/A
SH-18	REFCL - Grounding Conversion	◑	◑	○	◑	◑	N/A	N/A
SH-19[3]	Fire-resistant (FR) Wrap Expanded Deployment	N/A	N/A	N/A	N/A	N/A	N/A	N/A
SH-20	Transmission Proactive Splice Shunting	N/A	N/A	N/A	◔	N/A	N/A	N/A
SA-11	Early Fault Detection (EFD)	◔	○	◔	◔	◔	N/A	N/A
IN-1.1	Distribution High Fire Risk-Informed (HFRI) Inspections	○	●	●	◕	●	N/A	N/A
IN-1.2	Transmission HFRI Inspections	○	○	○	◑	○	N/A	N/A

Tracking ID	Activity	Contact from Object - Veg.	Contact from Object - Other	Wire-to-wire contact	Equipment Failure[2]	Other	PSPS	PEDS
IN-3	Distribution Infrared (IR) Scanning	○	○	○	◔	○	N/A	N/A
IN-4	Transmission Infrared and Corona Scanning	○	○	○	◔	○	N/A	N/A
IN-5	Generation HFRI Inspections	○	●	●	◕	●	N/A	N/A
VM-1	Hazard Tree Management Program	◕	N/A	N/A	N/A	N/A	N/A	N/A
VM-2.1	Additional Structure Brushing	N/A	N/A	N/A	◑	N/A	N/A	N/A
VM-2.2	Compliance Structure Brushing	N/A	N/A	N/A	◑	N/A	N/A	N/A
VM-4	Dead and Dying Tree Removal	◕	N/A	N/A	N/A	N/A	N/A	N/A
VM-7	Inspections for Vegetation Clearance from Distribution Lines	●	○	○	○	○	N/A	N/A
VM-8	Inspections for Vegetation Clearance from Transmission Lines	●	N/A	N/A	N/A	N/A	N/A	N/A

[1] Combines the effectiveness of covered conductor and FR Poles

[2] Equipment Failure is avg of Dist. Conductor EFF Model

[3] The activity addresses "Reliability Risk" after fire incidents to restoration faster

Legend	○	0% effectiveness at driver level
	◔	0% to 25% effectiveness at driver level
	◑	25% to 50% effectiveness at driver level
	◕	50% to 75% effectiveness at driver level
	●	75% to 100% effectiveness at driver level
	N/A	Driver is not applicable for mitigation

- Risk Mitigation Effectiveness Uncertainty: To the extent possible, SCE bases its assessment of activities' risk reduction effectiveness on quantitative data. However, sometimes quantitative data is either unavailable, due to the relative newness of an activity, or only available in a small size. In such situations, SCE will rely on SME judgment and supplement with quantitative data as it becomes available. SCE takes into account the certainty of an activity's effectiveness as it determines whether or not to deploy it and, if so, the magnitude of the deployment. Table SCE 6-02 below displays the sources of SCE's estimates of activities' risk mitigation effectiveness.

Table SCE 6-02: Mitigation Effectiveness Sources

Tracking ID	Activity	Estimate Source
SH-1	Covered Conductor	Formal analysis incorporating industry data with internal data
SH-2	Undergrounding Overhead Conductor	Formal analysis incorporating industry data with internal data
SH-5	Remote Controlled Automatic Reclosers Settings Update	Multiple SMEs
SH-14	Long Span Initiative (LSI)	Multiple SMEs
SH-17	Rapid Earth Fault Current Limiters (REFCL) - Ground Fault Neutralizer	Formal analysis incorporating industry data with internal data
SH-18	REFCL - Grounding Conversion	Formal analysis incorporating industry data with internal data
SH-19	Fire-resistant (FR) Wrap Expanded Deployment	Limited internal data
SH-20	Transmission Proactive Splice Shunting	Multiple SMEs
SA-11	Early Fault Detection (EFD)	Limited internal data
IN-1.1	Distribution High Fire Risk-Informed (HFRI) Inspections	Internal data
IN- 1.2	Transmission HFRI Inspections	Internal data
IN-3	Distribution Infrared (IR)	Limited internal data
IN-4	Transmission IR and Corona Scanning	Limited internal data
IN-5	Generation HFRI Inspections	Limited internal data
VM-1	Hazard Tree Mitigation Program	Internal data
VM-2.1	Additional Structure Brushing	Internal data
VM-2.2	Compliance Structure Brushing	Internal data

Tracking ID	Activity	Estimate Source
VM-4	Dead and Dying Tree Removal	Internal data
VM-7	Inspections for Vegetation Clearance from Distribution Lines	Internal data
VM-8	Inspections for Vegetation Clearance from Transmission Lines	Limited internal data

Risk Spend Efficiency (RSE): SCE developed its MAVF based on the six principles set forth in the S-MAP Settlement.[87] The MAVF is a framework to combine different consequences (e.g., safety, reliability and financial) into a generic unitless risk score, MARS, so that risks and mitigation alternatives can be compared on a uniform scale. SCE uses MARS, as appropriate, to establish baseline risk and to develop RSEs, given that MARS itself has no visible standalone value. RSEs help SCE evaluate the relative cost-effectiveness of potential activities; this in turn provides insight concerning prudently allocating resources, funding, and efforts to efficiently mitigate wildfire risk.

However, it would not be in the best interest of our customers or the communities we serve if SCE were to carry out a comprehensive wildfire risk mitigation plan based solely on RSEs. An RSE does not take into account certain operational realities, such as resource constraints, compliance issues, or service disruptions. Relying solely on RSEs could lead to significant parts of the system and potentially significant risk issues being left unaddressed. Indeed, the Commission's Safety and Enforcement Division (SED) noted that focusing solely on RSEs in selecting mitigations could be "suboptimal from an aggregate risk portfolio standpoint."[88] SED acknowledged that "mitigations are usually selected based on the highest risk spend efficiency score unless there may be some identified resource constraints, compliance constraints, or operational constraints that may favor another candidate measure with a lower RSE."[89] SCE agrees with this characterization. An activity with a higher RSE is generally favorable to one with a lower RSE. However, when an activity has a lower RSE, it could still be selected if, for example, it is easier to deploy quickly (e.g., critical care battery backup program to medical baseline customers affected by PSPS), addresses a particular risk driver that other activities do not (e.g., aerial inspections), or reduces overall risk even if it costs more (e.g., targeted undergrounding).

Also, consistent with the decisions[90] adopted in the CPUC's Rulemaking to Modernize the Electric Grid for a High Distributed Energy Resource Future, when deploying capital-intensive wildfire mitigations, such as targeted undergrounding or covered conductor, SCE

87 See S-MAP Settlement Agreement, pp. A-5 – A-6.

88 California Public Utilities Commission, Risk and Safety Aspects of Risk Assessment and Mitigation Phase Report of Pacific Gas and Electric Company, Investigation 17-11-003 (March 30, 2018), p. 18.

89 California Public Utilities Commission, Risk and Safety Aspects of Risk Assessment and Mitigation Phase Report of Pacific Gas and Electric Company, Investigation 17-11-003 (March 30, 2018), p. 18.

90 D.24-10-030, Decision Adopting Improvements to Distribution Planning and Project Execution Process, Distribution Resource Planning Data Portals, and Integration Capacity Analysis Maps, pp. 196, OP 17.

will consider if the circuit targeted for hardening should also be upgraded, whether due to load growth or another driver. In such a case, SCE may perform both projects (capacity upgrade and wildfire mitigation) together in a holistic and cost-effective manner.

Operational Feasibility / Lead Time to Deployment: An important feature of the mitigation activity selection process is obtaining an early understanding of the feasibility of implementing an activity, and the time required to plan, design and ultimately deploy the activity. Because SCE is focused on reducing wildfire risk as quickly as reasonably possible, our preference is toward activities that can be deployed more quickly in order to protect public safety. However, SCE carefully considers certain activities that may have longer lead times but that are necessary to provide substantial long-term risk reduction. SCE provides deployment times for its portfolios in Table SCE 6-05 in Section 6.1.3.2.

Cost to Customers: While the primary focus of our WMP is to reduce wildfire and PSPS risk at an appropriately urgent pace for the safety of our customers, cost is a factor in the decision-making process. In addition to RSEs that assess the risk reduction benefits of each activity against its costs, the total cost associated with any activity also needs to be considered to account for customer affordability and funding constraints. SCE notes that implementation costs for selected activities as a whole are provided in Table SCE 6-05 in Section 6.1.3.2 and at the individual level in Table 11 of the QDR.

Enabling Activity / Technology / Additional Benefits: Activities can be selected that do not directly reduce wildfire or PSPS risk, but rather they enable other initiatives to reduce risk, or to do so more efficiently. In our decision-making process, SCE will consider indirect but worthwhile benefits that activities may provide. Such indirect benefits may include improved system reliability, faster service restoration, improved communications with customers, etc. While valuable, these secondary benefits may be less influential in the wildfire risk reduction decision-making process compared to the other factors.

Compliance Requirement / Regulatory Guidance: In most circumstances, activities necessary to comply with local, state, or federal laws or regulations will be selected irrespective of other factors. In other words, compliance needs may weigh in favor of selecting the activity even if other factors seem to weigh against selecting the activity, particularly if the activity is the only prudent or feasible way to comply with the applicable law(s) or regulations(s). In addition, SCE takes into account Commission or other regulatory guidance and decisions when selecting wildfire mitigation activities and scope.

Resource Availability: With increasing work to maintain and operate the grid while upgrading it to mitigate safety and resiliency risks, there are increasing constraints on specialized resources such as planners, designers, engineers, field crews, etc. The scope of such resource constraints can affect SCE, utilities across the state, and even utilities nationwide at times. If requisite resources are not available, the potential activity could be temporarily deferred or de-scoped.

6.1.3.2 Activity Prioritization

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

- *Evaluate its potential activities. This evaluation will yield a prioritized list of activities. The objective is for the electrical corporation to identify the preferable activities for specific geographical areas. (Comparable to Risk Based Decision-making Framework, rows 12 and 29).*[91]

- *Identify the best activities for all geographical areas at a location-specific level to create a portfolio of projects expected to provide maximal benefits within known limitations and constraints. (Comparable to Risk Based Decision-making Framework, rows 12 and 26).*[92]

- *Explain when subject matter expertise is used as a part of activity selection, including the process used by subject matter experts (SMEs) to provide their judgement. Explain how the electrical corporation is optimizing its resources to maximize risk reduction. Describe how the proposed activities are an efficient use of electrical corporation resources and focus on achieving the greatest risk reduction with the most efficient use of funds and workforce resources.*

- *Discuss the interrelationships between different activities, in terms of how activities influence and impact implementation and respective effectiveness for risk reduction, and how the electrical corporation evaluates trade-offs between activities.*

- *Describe how grid needs, including future projected needs, (e.g., load capacity, peak demand, system flexibility)*[93] *influence activity prioritization.*

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

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91 Risk-Based Decision-Making Framework, Appendix A to D.24-05-064, California Public Utilities Commission, June 2024 at A-12 and A-21: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M533/K206/533206241.PDF.

92 Risk-Based Decision-Making Framework, Appendix A to D.24-05-064, California Public Utilities Commission, June 2024 at A-12 and A-21: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M533/K206/533206241.PDF.

93 These considerations should be in alignment with the CPUC's Decision Adopting Improvements to Distribution Planning and Project Execution Process, Distribution Resource Planning Data Portals, and Integration Capacity Analysis Maps, D.24-10-030 and with the CPUC's Rulemaking to Modernize the Electric Grid for a High Distributed Energy Resources Future, R.21-06-017.

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

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

Evaluate Mitigations

SCE's process for evaluating activities is described in detail in Section 6.1.3.1. High level schematics are provided as Figure SCE 6-01 and Figure SCE 6-02.

Optimized Mitigation Portfolios

After the activities are identified and evaluated pursuant to the process described above (SCE's evaluation process, criteria and high-level schematic are presented in Section 6.1.3), SCE designs portfolios of activities tailored to each of the three risk tranches.

Table SCE 6-03: Preferred Mitigation Portfolio per Risk Tranche

Risk Tranche	Preferred Mitigation Portfolio
Severe Risk Areas	TUG or REFCL/CC++, TVM/I++[94]
High Consequence Areas	CC++, TVM/I++
Other HFRA	VM/I++, TVM/I++

94 SCE's transmission lines also traverse SRAs, HCAs, and Other HFRAs.

Severe Risk Areas

For SRA locations, the threat to lives and property is elevated to such an extent that SCE has determined that for public safety reasons it is prudent to not just significantly reduce ignition risk expeditiously but minimize ignition risk in the long term to the extent practicable. Therefore, undergrounding is preferred unless covered conductor has already been installed or specific terrain or local issues require alternatives such as covered conductor with supplementary mitigations.

For example, mountainous regions with winding rights-of-way and rocky soil may not be conducive to undergrounding. In those situations, SCE would examine alternatives such as covered conductor paired with REFCL technology. On the other hand, undergrounding may be more feasible in flat areas with silty clay soil, making that the preferred option. Accordingly, SRAs are assigned either the portfolio known as TUG or REFCL/CC++.

Due to the potential impacts that a wildfire would have in these areas, when designing REFCL/CC++, SCE looked to mitigate all risk drivers to the extent reasonably possible. This necessarily means some cost-efficient redundancy, which is desirable because no activity matches undergrounding on its own. Thus REFCL/CC++ includes covered conductor, fast curve, vegetation management, and fusing to address contact from object; REFCL, asset inspections, and covered conductor to address equipment failure; and covered conductor to address wire-to-wire contact.

All options have implementation times of multiple months, up to as much as four years or more. As such, SCE will continue to use activities such as Fast Curve (FC) settings and asset inspections on the most frequent basis. SCE will also use PSPS as a tool of last resort to mitigate the risk of ignitions while the selected activity is designed, permitted, and constructed.

High Consequence Areas

For HCA locations, SCE’s strategy focuses on mitigating the majority of significant ignition risk drivers. SCE has selected CC++ for most of the HCAs that are still unmitigated, as it addresses all significant ignition risk drivers associated with overhead conductor, reduces more risk per dollar spent, and is faster and easier to deploy. Many HCAs may also by mitigated by REFCL, given that REFCL is sometimes deployed at the substation level, resulting in many circuit miles with varying risk profiles being mitigated.

Other HFRA

For areas classified at Other HFRA, SCE will harden overhead distribution circuits over time, as it replaces retired or damaged bare wires with covered conductor pursuant to its standards in HFRA. SCE will continue wildfire mitigation activities such as asset inspections, FC settings, and vegetation management that have relatively low incremental costs or are dictated by compliance requirements or local conditions.

Additionally, the deployment of technology like Early Fault Detection (EFD) may provide some monitoring benefit on these unmitigated aging assets (e.g., detect issues on the electric line before failure). Accordingly, Other HFRAs are assigned the VM/I++ portfolio of mitigations.

Although SCE is not currently targeting proactive hardening of these lines (with the exception of where it may be operationally efficient to do so), SCE periodically re-evaluates risks in these locations based on climate change impacts, refined risk methodologies and modeling, and/or more accurate information.

Transmission

Similar to SCE's overhead distribution lines, SCE's overhead transmission lines traverse SRAs, HCAs, and Other HFRAs. However, due to the higher voltage nature of transmission, activities that are extremely effective for distribution such as TUG and covered conductor, are either currently unavailable or prohibitively expensive for transmission. Thus, SCE's transmission system has its own portfolio of activities assigned to it, TVM/I++.

Table SCE 6-04 below summarizes the components of each portfolio and potential alternatives for each activity.

Table SCE 6-04: Activity Portfolios

Activity ID	Activity Name	TUG	REFCL/ CC++	CC++	VM/I++	TVM/I++
IN-1.1	Distribution HFRI Inspections	N/A	X	X	X	N/A
IN-1.2	Transmission HFRI Inspections	N/A	N/A	N/A	N/A	X
IN-3	Distribution IR	N/A	X	X	X	N/A
IN-4	Transmission IR and Corona	N/A	N/A	N/A	N/A	X
IN-5	Generation HFRI Inspections in HFRA	N/A	N/A	N/A	N/A	N/A
SA-11	Early Fault Detection (EFD)	N/A	X	X	X	N/A
SH-1	Covered Conductor	N/A	X	X	X	N/A
SH-14	Long Span Initiative (LSI)	N/A	N/A	N/A	N/A	N/A
SH-17	REFCL (Ground Fault Neutralizer)	N/A	X	N/A	N/A	N/A
SH-18	REFCL (Grounding Conversion)	N/A	X	N/A	N/A	N/A
SH-19	FR Wrap Expanded Deployment	N/A	X	X	N/A	N/A
SH-2	Undergrounding Overhead Conductor	X	N/A	N/A	N/A	N/A
SH-20	Transmission Proactive Splice Shunting	N/A	N/A	N/A	N/A	X
SH-5	Remote Controlled Automatic Reclosers Settings Update	X	X	X	X	N/A
VM-1	Hazard Tree Management Program	N/A	X	X	X	N/A
VM-14	Expanded Clearances for Non-Energized Facilities	N/A	N/A	N/A	N/A	N/A
VM-2.1	Additional Structure Brushing	N/A	X	X	X	X
VM-2.2	Compliance Structure Brushing	N/A	X	X	X	X
VM-4	Dead and Dying Tree Removal	N/A	X	X	X	N/A
VM-7	Distribution VM Clearances	N/A	X	X	X	N/A
VM-8	Transmission VM Clearances	N/A	N/A	N/A	N/A	X

Table SCE 6-05 below summarizes the relative effectiveness of each portfolio across risk drivers.

Table SCE 6-05: Efficacy of Activity Portfolios

Attribute	TUG	REFCL/CC++	CC++	VM/I++	TVM/I++
Approximate Average lifetime cost/mile [1]	$2.9M-$4.5M+ [2]	$1.4M-$2.6M	$1.4M-$1.6M	$0.37M-$0.48M [3]	$0.16M-$0.21M
Deployment Speed [4]	25-48+ months	18-36+ months	16-24+ months	Annual	Annual
Phase-to-phase incandescent particle ignition [5] mitigation	High	High	High	Low	Low
Phase-to-ground incandescent particle ignition [6] mitigation	High	High	High	Medium	Medium
Wire-down ignition mitigation	High	High	High	Low	Low
Equipment Failure mitigation	High	High	Medium	Medium	Medium

[1] Cost estimates associated with the VM/I++ and TVM/I++ portfolio are lifetime O&M costs and excludes Capital costs.

[2] Based on current analysis, SCE estimates that a small population of underground miles may fall below this range.

[3] Estimate of lifetime cost of the VM/I++ and TVM/I++ portfolio in Other HFRAs.

[4] Typical deployment timelines based on historical installations and projected costs. Actual timelines can vary further due to local conditions.

[5] Examples include conductor to conductor contact, balloon coming between two phase wires.

[6] Examples include tree to conductor contact, animal contact between phase wires and pole.

Adjustments to Portfolios

As described in Section 5.2.1.2.2, the Review and Revise stage consists of the team of SMEs reviewing unhardened segments and local conditions to determine if the segments were appropriately categorized during the Initial Risk Categorization stage. SCE leverages this evaluation process to make adjustments to activity portfolios for specific segments if local conditions make an alternative activity more appropriate. For example, if a long line of overhead conductor runs through a SRA and serves what appears to be relatively small load, the team may recommend a Remote Grid option be evaluated in lieu of undergrounding. Further, if during a feasibility review the activity is considered infeasible in a specific location due to local conditions, the Review and Revise team will recommend an alternative activity.

6.1.3.3 Activity Scheduling

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

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

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

- *How the electrical corporation schedules activities*
- *How the electrical corporation incorporates the amount of time it takes to implement the activities when determining initiative effectiveness and prioritization. This must include evaluations of cumulative risk exposure while the initiative is being implemented, as well as interim activities.*
- *How the electrical corporation evaluates whether an interim activity is needed and, if so, how an interim activity is selected (see Section 6.2.2)*
- *How the electrical corporation monitors its progress toward its targets within known limitations and constraints. This should include descriptions of*

mechanisms for detecting when an activity is off track and for bringing it back on track.

- *How the electrical corporation measures the effectiveness of activities (e.g., tracking the number of PEDS deenergizations that had the potential to ignite a wildfire due to observed damage/contact prior to re-energization). The mitigation category sections of these Guidelines (Sections 8–12) include specific requirements for each activity.*

Initiative Implementation Process and Schedule

While SCE's risk models continue to evolve, a guiding principle in scheduling mitigation initiatives is to prioritize work to reduce wildfire risk as expeditiously and efficiently as possible.

The following describes SCE's approach to mitigation scheduling by major mitigation category:

- Grid Hardening activities are scheduled and scoped on a multi-year basis due to the long lead times to perform advanced planning tasks such as engineering, sourcing, permitting, municipal coordination, and resource allocation.
- Inspections are scheduled on a risk-informed annual basis as described in Sections 8.3.1.2 and 8.3.2.2. At a minimum, SCE performs inspections on a cadence that meets or exceeds CPUC requirements with the riskiest areas getting the most frequent inspections.
- Vegetation Management activities are scheduled as described in Sections 9.2.1.5 and 9.2.2.5. SCE performs vegetation management activities that meet or exceed CPUC requirements.

Activities related to Situational Awareness, Emergency Preparedness, and Public Communication, Outreach, and Education are typically performed on an ongoing basis, with some seasonal variation, and are not scheduled in the same sense as hardening, inspection, and vegetation management activities. Please see Sections 10, 11, and 11.4 (respectively) for further detail.

Generally, SCE implements its wildfire mitigations through a process that consists of four phases: Initiate, Planning, Scheduling and Execute. The phases are defined below:

- Initiate is the process of developing the scope based on risk data.
- Planning involves engineering and design as well as initiating early permit application requirements
- Scheduling involves performing standard permitting and easement processes, environmental clearance processes, and verifying other permits. Additionally, during this phase materials are acquired, work is scheduled, and circuit maps finalized.
- Execution involves the construction and deployment of the activity.

For the Initiate phase, initial selection and scoping is based on areas of highest risk, as defined by the three risk tranches in the IWMS Framework. SCE addresses those circuit-segments and circuits that present the greatest risk. However, SCE will often bundle work related to multiple and/or contiguous circuit-segments together to achieve operational efficiencies. For example, the risk associated with each circuit may not be uniform along its length. In other words, the risk can vary within a circuit, especially if that circuit traverses various parts of HFRA and is exposed to varying topography and vegetation that can influence fire propagation and consequence.

In some cases, it may be operationally efficient and prudent to remediate relatively lower risk segments of a circuit at the same time that relatively higher risk segments of the same circuit are addressed, instead of sending multiple crews out at different times (which would also require the development of separate work scope packages). Bundling work can also reduce community and environmental impacts by reducing the amount of times that crews visit a location to perform work.

After the scope is selected, SCE goes into the Planning phase. During this phase, a project manager is assigned to oversee the work and design resources are assigned to initiate the work order, design the project, map the circuit miles, procure the materials, and initiate obtaining permits. On average, this process takes six to nine months for CC and nine to fifteen months for TUG, assuming there are no competing resources for planning and no delays in environmental/agency approvals. Relatively higher risk segments might be remediated after other segments if it is more difficult to design or procure permits for the higher risk segments.

Scheduling begins with SCE's regional districts when the work is fully designed, permitted (including obtainment of easements), and cleared of environmental constraints. Scheduling is when materials are acquired, permits are verified, work is scheduled, and circuit maps are revised if found inconsistent with what is shown in SCE's database. Design resources and project management teams also collaborate with customers, local government, and state agencies to provide project details to obtain necessary easements prior to the start of construction. Scheduling can take between six to nine months for CC and nine to fifteen months for TUG.

In the Execution phase, construction will proceed with necessary environmental monitoring if required. There are many factors that may affect the construction timeline including, for example, the size of the project, location of the project, terrain, environmental restrictions, weather, material and/or resource availability, and ensuring adherence to city requirements.

Sample timelines for implementation of SCE's mitigation initiatives, assuming favorable conditions and no significant delay due to permitting or other reasons, are shown below in Table SCE 6-06. For inspection and vegetation management activities, the sample timelines are shown for the remediation portion of the work, as opposed to the inspection.

Table SCE 6-06: Project Timelines for Select Wildfire Mitigations

Tracking ID	Mitigation	Initiate	Planning	Schedule	Execute	Total
SH-1	Covered Conductor	2-3 months	6-9 months	6-9 months	2-3 months	16 - 24 months
SH-2	Undergrounding Overhead Conductor	2-3 months	9-15 months	9-15 months	5-15 months	25 - 48 months
SH-5	Remote Controlled Automatic Reclosers Settings Update	1 - 3 months	1-3 months	1 - 2 months	1 - 4 months	4 - 12 months
SH-14	Long Span Initiative (LSI)	2 - 3 months	1 - 9 months	1 - 3 months	1 - 6 months	5 - 21 months
SH-17	Rapid Earth Fault Current Limiters (REFCL) - Ground Fault Neutralizer	2 - 3 months	12 - 72 months	4-9 months	6 - 12 months	24 - 96 months
SH-18	REFCL - Grounding Conversion	2 - 3 months	4 - 18 months	2 - 4 months	2 - 4 months	10 - 29 months
SH-19	Fire-resistant (FR) Wrap Expanded Deployment	2 -3 months	3 - 4 months	10 - 11 months	10 - 11 months	15 - 18 months
SH-20	Transmission Proactive Splice Shunting	1 - 2 months	4 - 5 months	2 - 3 months	1 - 2 months	8 - 12 months
SA-11	Early Fault Detection (EFD)	1 - 2 months	3 - 6 months	2 - 4 months	3 - 6 months	9 - 18 months

Interim Strategy Development

Please see Section 6.2.2 Interim Mitigation Initiatives for the explanation of interim strategy development.

Project Management Controls/Target Tracking

On an annual basis, SCE's performance management organization works with the strategy and execution teams to develop internal monthly and/or quarterly project plans for all WMP activities and targets.

The project plans are used in conjunction with other lagging and leading indicators to measure the monthly performance of the WMP activities in achieving their targets, as well as to proactively identify issues throughout the year that may affect an activity's performance. Key performance insights are consolidated into a performance dashboard and presented and discussed on a monthly basis with SCE executives and key leaders. The purpose of the dashboard is to:

- Clearly communicate WMP activities
- Monitor progress toward monthly / annual goals
- Measure delivery of key objectives
- Develop corrective action plans when activities fall behind plan

Performance issues are immediately raised within the respective execution teams, including identification of the key drivers / issues and a plan for resolution and recovery.

Performance highlights are also summarized and provided monthly to OEIS with a monthly report-out on activities that are behind-plan or at-risk of meeting their year-end targets.

On a quarterly basis, SCE further summarizes progress toward meeting its WMP commitments through development and delivery of the following deliverables to Energy Safety:

- Quarterly Notification Letter
- Quarterly Data Report - Geographic Information System (GIS) Data
- Quarterly Data Report – Wildfire Mitigation Data Tables

On an annual basis, SCE submits an Annual Report of Compliance (ARC) that details SCE's performance against its WMP, including a review of the wildfire mitigation initiatives implemented and an accounting of whether SCE met its performance targets, whether spending on any of those initiatives did not reach anticipated levels, and whether SCE followed its QA/QC processes.

SCE closely monitors the financial impacts of its wildfire mitigation portfolio on a regular basis, including through the following mechanisms:

Recording and reporting of actual spend: Costs incurred for WMP activities record to specific wildfire- related internal accounting codes. This allows SCE to properly track recorded costs against the WMP forecast.

Sarbanes-Oxley (SOX) controls: On a monthly basis, SCE's Finance organization performs SOX control testing on distribution inspection and remediation work orders to help ensure proper accounting. The Finance organization also performs SOX control testing on selected mitigations such as vegetation management, aerial inspections, wildfire remediations, and covered conductor expenditures to help ensure current monthly goods and services received and work performed are properly accrued and accounted for.

Performance Reviews and Year-End Projections: On a monthly basis, SCE's Finance organization partners with execution organizations to refresh assumptions for year-end financial projections for each activity. Throughout the course of the year, various factors may impact the achievement of year-end financial forecasts, including resource costs, work delays or acceleration, etc. SCE reviews variance analyses for work performed to-date, understands changes to cost-pers, and evaluates impacts to year-end financial projections. Any material updates to activity financial projections are approved through internal governance.

Activity Effectiveness

SCE uses metrics such as outages and ignitions, along with other data such as field observations and ignition investigations, to help inform its annual evaluation and calculation of mitigation initiatives' effectiveness against risk drivers, as discussed in Section 6.1.3.1.

SCE also considers learnings from observed risk events as potentially relevant to evaluating mitigation effectiveness. This discussion can be found in Section 13 (Lessons Learned). These types of learnings may provide insight that SCE uses to adjust or change its approach.

Risk outcomes and events will vary from year to year based on factors such as weather, system conditions, and other variables. SCE actively monitors risk events and performance metrics, but also understands that a complete understanding of activity effectiveness takes several years of observed field data to account for short-term and annual variations inherent in any real-world deployment.

SCE may also use formal studies and analysis to understand activity effectiveness. For example, as described in SCE's Covered Conductor Compendium,[95] SCE performed benchmarking with other utilities around the world, reviewed literature for best practices, and worked with research institutions and suppliers to perform testing on the effectiveness of covered conductor.

Additionally, SCE worked with other California IOUs to commission Exponent, an independent third party, to review potential failure modes of overhead lines, both bare and covered, and perform additional testing to understand the effectiveness of covered conductor by evaluating phase-to-phase contact and simulated wire-down testing. The third party review concluded that "CCs were 100% effective at preventing arcing and ignition in tested scenarios at rated voltages. This is consistent with documented field experience as reported in Exponent's Phase I report."[96]

6.1.3.4 Key Stakeholders for Decision Making

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

- *Identify each key stakeholder group (e.g., electrical corporation executive leadership, the public, state/county/Tribal Nation public safety partners)*

95 SCE's Covered Conductor Compendium is available at https://www.sce.com/wmp

96 See "Joint IOU Covered Conductor Testing Cumulative Report 12-22-22_Redacted", Exponent, pg. vi this document is also available at https://www.sce.com/wmp

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

Table 6-2: SCE Stakeholder Roles and Responsibilities in the Decision-Making Process

Stakeholder	Stakeholder Point of Contact	Electrical Corporation Point of Contact	Stakeholder Role	Engagement Methods	Activity	Level of Engage ment for Activity
SCE Executive Leadership	Director, Asset & System Intelligence	Director, Asset & System Intelligence	• Provides guidance and decision making on wildfire mitigation near and long-term planning • Informed on wildfire mitigation execution status • Informed and provides guidance on strategy/risk prioritization methodologies	Weekly Internal Meetings	All	Internal
Office of Energy Infrastructure Safety (OEIS or Energy Safety)	OEIS Deputy Director, Director of OEIS	Principal Manager, Regulatory Affairs & Compliance - State Regulatory Relations	• Defines WMP requirements • Participates and provides guidance in working groups • Reviews wildfire mitigation plan submissions and provides feedback, areas for continuous improvement, and issues approval or denial of plan	• Weekly meetings following submission of WMP • Biweekly participation in working groups • Written comments • Ad hoc meetings	All	Local

Stakeholder	Stakeholder Point of Contact	Electrical Corporation Point of Contact	Stakeholder Role	Engagement Methods	Activity	Level of Engage ment for Activity
California Public Utilities Commission (CPUC)	SED Director	Principal Manager, Regulatory Affairs & Compliance - State Regulatory Relations	• Provides guidance and review of CPUC-mandated risk analysis used to inform wildfire and PSPS mitigations; authorizes cost recovery for wildfire and PSPS mitigations in consideration of risk reduction, cost efficiency, affordability, and other factors.	• Ad hoc meetings • Comments, workshop, CPUC rulings and decisions	All	Local
Local Governments (including city councils, county boards and tribal governments)	Various local representative s	Director, Local Public Affairs	• Provides feedback on implementation of SCE's wildfire initiatives • Informed on SCE's strategy as presented in WMP	Ad hoc meetings	All	Local; tribal
Local Fire Agencies (includes Cal FIRE)	Various Southern California Fire Chiefs	Managing Director, Regulatory Relations Director, Business Resiliency	• Provides guidance on wildfire mitigations including Fire Suppression • Informed on SCE's strategy as presented in WMP	Ad hoc meetings	All	Local

Stakeholder	Stakeholder Point of Contact	Electrical Corporation Point of Contact	Stakeholder Role	Engagement Methods	Activity	Level of Engagement for Activity
Cal OES	Assistant Director of Response Operations	Principal Manager, Regulatory Affairs & Compliance - State Regulatory Relations	• Provides statewide guidance on wildfire mitigations including PSPS • Participates on the board of the AFN Council	Ad hoc meetings	All	Local
Access and Function Needs (AFN) Advisory Council	Various	VP Customer Engagement Division	Raises awareness of the needs of our AFN populations and to collaborate on initiatives that will advance communications, resources and support for AFN populations, all aimed at PSPS impact mitigation	Monthly meetings (or more frequent as necessary)	Wildfire Safety Community Meetings; Customer Research and Education; Critical Care Backup Battery; Portable Power Station and Generator Rebates	Local
Public Advocates Office and other stakeholders	Various	Various	Participates in Energy Safety-led working groups and provides input.	Pursuant to working group schedules	All	Local
Wildfire Safety Advisory Board	Board Members	Various	Advises OEIS on requirements for WMPs, holds workshops, provides comments on advisory opinions.	Comments, public meetings.	All	Local

SCE executive leadership is actively involved in directing all aspects of the WMP process. After selecting activities and deciding on scope for each one pursuant to the processes described in Sections 6.1.3, SCE's program leads engage with their leadership to review and approve these decisions. SCE's executive leadership then reviews the decisions with the program leads and either approves or recommends changes.

The SCE executive leadership is also regularly briefed on WMP status, including progress towards mitigation goals set forth in the WMP. SCE's executive leadership provides guidance and decisions on near- and long-term wildfire and PSPS mitigation strategies, risk analyses, planning activities, resource allocation, and compliance matters. New strategy/risk prioritization methodologies are reviewed by SCE's senior executives at standing weekly and biweekly wildfire mitigation forums.

Internal wildfire safety meetings are held weekly at a minimum, and more frequently as needed, to advance strategic wildfire mitigation and PSPS planning and execution.

SCE meets routinely with key stakeholders to gather feedback and to communicate decisions related to important wildfire-related information, such as short- and long-term wildfire and PSPS mitigation plans as discussed in the WMP filings. SCE engages with various governmental regulatory agencies, including Energy Safety and the CPUC.

SCE adheres to guidelines established by Energy Safety in developing the WMP. After the WMP is filed, SCE responds to discovery requests issued by Energy Safety and other stakeholders. SCE also participates in regular joint-utility working groups meetings mandated by Energy Safety on topics such as risk modeling, grid hardening, and vegetation management.

SCE engages with the CPUC on matters pertaining to wildfire and PSPS policies, cost recovery, and other areas within the CPUC's jurisdiction. The CPUC reviews SCE's requests to recover the costs to implement our WMP and provides funding authorization based on those reviews. The CPUC will also review these requests to ensure adherence with CPUC policies and practices required through various wildfire, risk, and PSPS-related proceedings managed by the CPUC. SCE will hold meetings with the CPUC, largely on an ad hoc basis, with a representative from SCE's Regulatory Affairs department and requisite SMEs.

SCE meets with local governments including city councils, county boards and tribal governments. At these meetings, SCE shares strategic decisions made that will impact the local area and gathers feedback on SCE's wildfire programs and community needs to understand what is working well and to identify areas of improvement to incorporate into wildfire planning. For example, SCE endeavors to minimize the impacts of outages required to perform wildfire mitigation and other construction work by working with local governments and communities to alleviate outage impacts. SCE also engages with local and state agencies, large commercial and industrial customers, and representatives from critical infrastructure facilities to highlight SCE's wildfire mitigation priorities and PSPS-related work.

Additionally, SCE participates in the Access and Functional Needs (AFN) Advisory Council, which meets at least monthly to explore wildfire and PSPS risk mitigation strategies, policies, and procedures specific to AFN customers. SCE will also relay specific details related to programs or initiatives targeted to further assist AFN customers.[97]

6.2 Wildfire Mitigation Strategy

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

6.2.1 Anticipated Risk Reduction

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

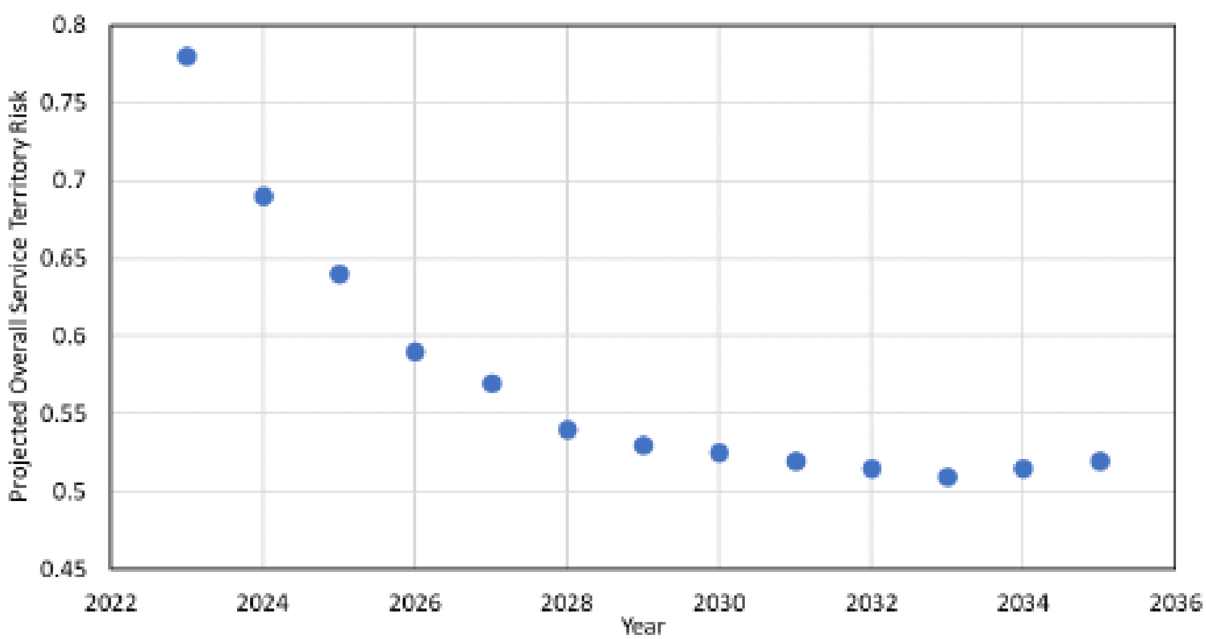
The electrical corporation must provide:

- *Projected overall risk reduction*
- *Projected risk reduction on highest-risk circuits over the three-year WMP cycle*

6.2.1.1 Projected Overall Risk Reduction

In this section, the electrical corporation must provide a figure showing the projected overall utility risk in its service territory as a function of time, assuming the electrical corporation meets the planned timeline for implementing the activities. The figure is expected to cover at least ten years. If the electrical corporation proposes risk reduction strategies for a duration longer than ten years, this figure must show that corresponding time frame. Figure 6-1 is an example of a graph showing the long-term projected changes in overall risk

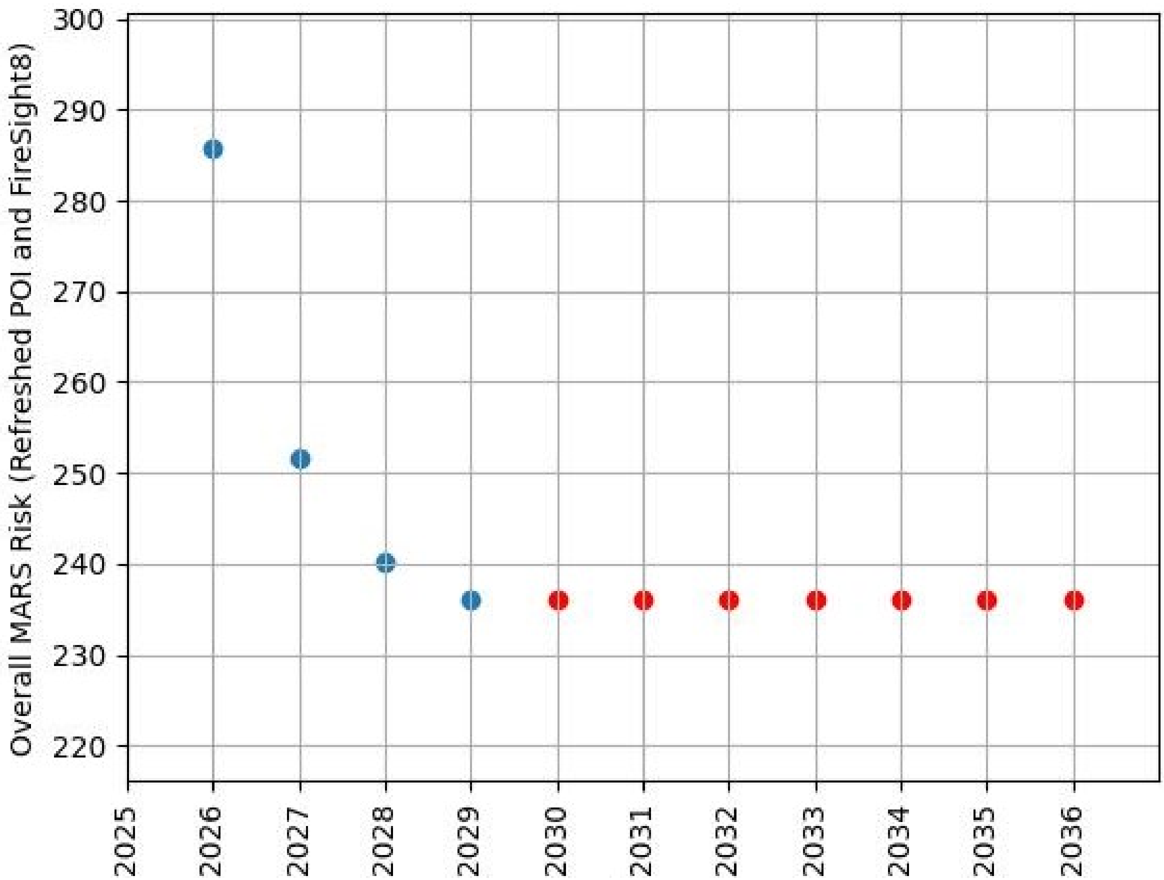
Figure 6-1: Example of Projected Overall Service Territory Risk



97 Engagement with AFN populations is discussed in more detail Section 11.4.4.

As part of IWMS, SCE uses MARS to help quantify risk at a particular point of time and then to demonstrate risk reduction. Please see Figure 6-1, where SCE has projected overall risk in HFRA for the years 2026 through 2029 (represented by the blue dots), which covers the current WMP cycle and the forecast period in SCE's 2025 General Rate Case. SCE has assumed a steady state risk level for the years of 2030 through 2036 (represented by the red dots), as SCE does not currently have planned or scoped incremental mitigations after 2029, other than the replacement of retired overheard bare distribution wire with covered conductor pursuant to SCE's design standards in HFRA.

Figure 6-1: SCE Projected Overall HFRA Risk



6.2.1.2 Risk Impact of Activities

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

The electrical corporation must provide the cost benefit score,[98] broken out by overall utility risk, wildfire risk, and outage program risk. The score should be calculated for the activity overall based on overall average activity effectiveness and average unit costs.

The electrical corporation must calculate the expected % HFTD/HFRA[99] covered for each of its initiative activity targets over the WMP cycle. The expected % HFTD/HFRA covered is the percentage of HFTD and HFRA being worked on by the given activity from the first year of the Base plan to the last year of the Base plan. This could include the number of circuit miles or the number of assets. For example:

For covered conductor installations, the expected installations from Jan. 1, 2026, through Dec. 31, 2028 = 600 circuit miles

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

SCE has populated Table 6-3 with activities that have risk reduction values. The calculations below correspond to the values in Table 6-3.

Table 6-3: SCE Risk Impact of Activities

Activity	Activity Section #	Activity Effectiveness – Overall Risk	Activity Effectiveness – Wildfire Risk	Activity Effectiveness - Outage Program Risk	Risk Spend Efficiency Score - Overall Risk [1]	Risk Spend Efficiency Score - Wildfire Risk	Risk Spend Efficiency Score – Outage Program Risk	% HFTD Covered [2]	% HFTD/ HFRA Covered [3]	Expected % Risk Reduction [4]	Model(s) Used to Calculate Risk Impact
Covered Conductor (SH-1)	8.2	60%	60%	62%	1,254	1,239	15.2160	4.72%	N/A	0.46634%	POI; FireSight8
Undergrounding Overhead Conductor (SH-2)	8.2	97%	97%	98%	1,468	1,465	3.6341	2.78%	N/A	1.91101%	POI; FireSight8
REFCL GFN (SH-17)	8.7	52%	52%	52%	18,920	18,918	1.7343	4.86%	N/A	1.42473%	POI; FireSight8
REFCL GC (SH-18)	8.7	48%	48%	48%	22,701	22,698	3.5043	0.49%	N/A	1.56562%	POI; FireSight8
FR Wrap Expanded Deployment (SH-19)	8.2	1%	1%	N/A	235	235	N/A	2.07%	N/A	0.00267%	POI; FireSight8
Transmission Proactive Splice Shunting (SH-20)	8.2	14%	14%	N/A	934	934	N/A	3.23%	N/A	0.00372%	POI; FireSight8
Remote Controlled Automatic Reclosers Settings Update (SH-5)	8.7	8%	N/A	8%	102	N/A	102.1654	1.07%	N/A	0.00080%	POI; FireSight8
Long Span Initiative (SH-14)	8.2	7%	7%	7%	1,289	1,289	0.0016	0.48%	N/A	0.02448%	POI; FireSight8
Distribution HFRI Inspections (Ground and Aerial) (IN-1.1)	8.3	81%	81%	82%	3,454	3,454	0.0279	100.00%	N/A	4.97708%	POI; FireSight8
Transmission HFRI Inspections (Ground and Aerial) (IN-1.2)	8.3	77%	77%	N/A	113	113	N/A	100.00%	N/A	0.03265%	POI; FireSight8

Activity	Activity Section #	Activity Effectiveness – Overall Risk	Activity Effectiveness – Wildfire Risk	Activity Effectiveness - Outage Program Risk	Risk Spend Efficiency Score - Overall Risk [1]	Risk Spend Efficiency Score - Wildfire Risk	Risk Spend Efficiency Score – Outage Program Risk	% HFTD Covered [2]	% HFTD/ HFRA Covered [3]	Expected % Risk Reduction [4]	Model(s) Used to Calculate Risk Impact
Distribution Infrared Scanning (IN-3)	8.3	3%	3%	3%	27	27	0.0001	72.21%	N/A	0.00009%	POI; FireSight8
Transmission Infrared and Corona Scanning (IN-4)	8.3	17%	17%	N/A	9	9	N/A	50.42%	N/A	0.00001%	POI; FireSight8
Generation HFRI Inspections (IN-5)	8.3	81%	81%	82%	130	130	0.0001	0.10%	N/A	0.00010%	POI; FireSight8
HTMP (VM-1)	9.2	60%	60%	60%	742	742	0.0001	100.00%	N/A	0.10789%	POI; FireSight8
Dead & Dying Tree Removal (VM-4)	9.2	51%	51%	51%	1,654	1,654	0.0003	100.00%	N/A	0.16049%	POI; FireSight8
Inspections for Vegetation Clearance from Distribution Lines (VM-7)	9.2	97%	97%	97%	214	214	0.0004	100.00%	N/A	5.04072%	POI; FireSight8
Inspections for Vegetation Clearance from Transmission Lines (VM-8)	9.2	96%	96%	N/A	356	356	N/A	100.00%	N/A	1.12627%	POI; FireSight8
Additional Structure Brushing (VM-2.1)	9.4	32%	32%	32%	16,304	16,304	0.0119	36.13%	N/A	11.86671%	POI; FireSight8
Compliance Structure Brushing (VM-2.2)	9.4	32%	32%	32%	42.253	42.253	0.0216	17.25%	N/A	18.55938%	POI; FireSight8
Early Fault Detection (EFD) (SA-11)	10.3	10%	10%	10%	5,654	5,654	0.4197	6.42%	N/A	0.24404%	POI; FireSight8

[1] SCE has opted to use Risk Spend Efficiency Scores in lieu of Cost Benefit Ratios

[2] SCE uses a 200-foot buffer extended from the HFTD to account for possible internal mapping discrepancies of assets as an additional margin for scoping enhanced wildfire mitigation activities. See D.19-05-038, Decision on Southern California Edison Company's 2019 Wildfire Mitigation Plan Pursuant to Senate Bill 901, p. 7.

[3] HFTD/HFRA meaning the combination of all HFTD and HFRA. At the time of this filing, all of SCE's HFRA is now consistent with the CPUC HFTD maps. Please see % HFTD Covered.

[4] This is the expected risk reduction from the first year of the Base plan to the last year of the Base plan based on implementation of the activity.

As SCE deploys mitigations, the underlying risk profile changes to reflect, 1) reduced risk for those mitigated risk drivers and, 2) an increase in unmitigated risk drivers as a percentage of total risk. In other words, as mitigations are deployed in the field for an increasing period of time and in combination with other wildfire mitigations, observed data increasingly reflects a "post-mitigation" view in which it is difficult to isolate and empirically measure the effects of individual mitigations.

Table 6-3 above describes covered conductor effectiveness as 60%, which is different from the 72% effectiveness figure determined in prior years. Generally, SCE's deployment of covered conductor has reduced many of the drivers that covered conductor is effective at mitigating, such as wire-to-wire contact and vegetation contact. SCE's estimates in the past represented the effectiveness of covered conductor when compared to bare wire based on the risk profile at the time. SCE has now covered approximately 62% of its HFRA circuit miles, and this has resulted in a shift in the underlying risk profile, including how much risk remains on a prospective basis of the risk drivers that covered conductor mitigates. Nevertheless, covered conductor is still as effective (72% overall) when compared to bare conductor.

Another way to understand this concept is to consider the hypothetical example of Mitigation "A" (see Figure SCE 6-07). The deployment of Mitigation A over two years results in changes to the underlying risk profile and to Mitigation A's calculated mitigation effectiveness over time, which goes from 75% to 50% as observed risk events decrease due to deployment. Hence a difference emerges between theoretical mitigation effectiveness and observed mitigation effectiveness.

Figure SCE 6-07 - Illustrative Example of Risk Profile Changes due to Mitigation "A" Deployment

Year 1: Initial Mitigation A Deployment

Sub-Driver	Year 1 Number of Ignitions	Mitigation "A" Effectiveness Against Sub-driver
Balloon Contact	10	100%
Tree Fall-In	10	50%

According to the chart above, deployment of Mitigation A in year 1 would reduce the number of ignitions from balloon contact by 10, since it is 100% effective against this driver. Conversely, Mitigation A would only reduce the number of ignitions by 5 for tree fall-in risk, since it is 50% effective against this driver. The total mitigation effectiveness for A in Year 1 is therefore 75% since:

$$\frac{(10 \text{ ignitions from balloon contact} * 100\%) + (10 \text{ ignitions from tree fall-in} * 50\%)}{20 \text{ ignitions total}} = \mathbf{75\%}$$

Year 2: Additional Mitigation "A" Deployment

Sub-Driver	Year 2 Number of Ignitions	Mitigation "A" Effectiveness Against Sub-driver
Balloon Contact	0* *(from 10 in Year 1)	100%
Tree Fall-In	5** **(from 10 in Year 1)	50%

In Year 2, Mitigation A is deployed again. This time, however, the underlying risk profile has changed: only 5 ignitions remain due to tree fall-in and 0 ignitions due to balloon contact because of the risk already reduced from the previous year's deployment of Mitigation A. The total mitigation effectiveness for A in Year 2 is therefore 50% since:

$$\frac{(0 \text{ ignitions from balloon contact} * 100\%) + (5 \text{ ignitions from tree fall-in} * 50\%)}{5 \text{ ignitions total}} = \mathbf{50\%}$$

In the illustrative example above, although the total mitigation effectiveness for Mitigation A had reduced by 25 percentage points in Year 2, Mitigation A remains as effective in Year 2 against the drivers it is supposed to mitigate as it was in Year 1.

SCE presents below its general approach to calculations for each of the values presented in Table 6-3 as well as how it considers risk after activity deployment. Since the effectiveness calculations for ignition frequency, PSPS consequence, and wildfire consequence are constructed differently and measure different risks, they are not summed. The methodology below describes how SCE addresses these differences in providing the activity effectiveness values for Table 6-3. SCE notes that activity effectiveness - overall risk is not a summation of activity effectiveness - wildfire risk and activity effectiveness - outage program risk, but rather represents the mitigation's effectiveness against relevant risk drivers.

Activity Effectiveness - Overall Risk

Figure SCE 6-08 – Weighting factor calculation for Activity Effectiveness – Overall Risk

$$weighting\ factor_i = \frac{\sum\ relevant\ subdriver\ i}{\sum\ all\ relevant\ subdrivers}$$

The weighting factor for sub-driver, i, is defined as the sum of the relevant (i.e., non-zero), i, drivers divided by the total across all relevant drivers. For a discussion of which weighting factors are considered relevant, please see below weighting factors discussions and calculations under Activity Effectiveness – Wildfire Risk and Activity Effectiveness – Outage Program Risk.

Figure SCE 6-09: Activity Effectiveness – Overall Risk Calculations

$$a)\ Activity\ Effectiveness\ =\ \sum_{i=1}^{n} WF_i\ \cdot ME\%_i$$

OR

b) $Activity\ Effectiveness\ =\ \sum_{i=1}^{n} OP_i \cdot ME\%_i$

The activity effectiveness – overall risk depends on which sub-drivers are most prevalent (i.e., wildfire or PSPS consequence). For those mitigations whose sub-drivers are predominantly wildfire, SCE uses equation (a). For those mitigations whose sub-drivers are predominantly PSPS consequence, SCE uses equation (b). For PEDS mitigations, SCE uses equation (a).[100]

The activity effectiveness – overall risk is defined by the sub-driver, i, weighting factors multiplied by the sub-driver i mitigation effectiveness values across all the sub-drivers.

Activity Effectiveness – Wildfire Risk

Figure SCE 6-10: Weighting factor calculation for Activity Effectiveness – Wildfire Risk, Probability of ignition

$$weighting\ factor_i = \frac{\sum PoI\ \ of\ relevant\ subdriver\ i}{\sum PoI\ \ of\ all\ relevant\ subdrivers}$$

The weighting factor for sub-driver, i, is defined as the sum of the relevant (i.e., non-zero) wildfire risk, i, drivers' POI divided by the total POI across all relevant wildfire risk drivers.

OR

Figure SCE 6-11: Weighting factor calculation for Activity Effectiveness – Wildfire Risk, Wildfire Consequence

$$weighting\ factor_i = \frac{mean(MARS\ Conseq\ Component_i)}{mean(MARS\ Consequence)}$$

The weighting factor for sub-driver, i, is defined as the average of the relevant (i.e., non-zero) risk, i, drivers' MARS Consequence Components divided by the MARS Consequence Component across all wildfire risk drivers. SCE uses this weighting factor when the mitigation impacts wildfire consequence (e.g., FR wraps) rather than the wildfire ignition sub-drivers.

Figure SCE 6-12: Activity Effectiveness – Wildfire Risk Calculation

$$Activity\ Effectiveness\ =\ \sum_{i=1}^{n} WF_i \cdot ME\%_i$$

The activity effectiveness – wildfire risk is defined by the sum of the wildfire risk sub-driver, i, weighting factors multiplied by the sub-driver, i, mitigation effectiveness values across all the sub-drivers.

Activity Effectiveness – Outage Program Risk

Figure SCE 6-13: Weighting factor calculation for Activity Effectiveness – Outage Program Risk, PEDS

a) $weighting\ factor_i = \frac{\sum PEDS\ outage\ likelihood\ of\ relevant\ subdriver\ i}{\sum PEDS\ outage\ likelihood\ of\ all\ relevant\ subdrivers}$

The weighting factor for sub-driver, i, is defined as the sum of the relevant (i.e., non-zero) protective equipment and device settings (PEDS) outage likelihood drivers, i, divided by the total outage likelihood across all relevant PEDS outage likelihood drivers. For its calculation of PEDS, SCE assumed the same mitigation effectiveness on PEDS outage likelihood risk drivers as on wildfire risk drivers, resulting in similar activity effectiveness numbers for wildfire and PEDS-related outage program risk. For example, vegetation contact with an energized line could lead to an ignition but it also represents potential faults and outages.

OR

Figure SCE 6-14: Weighting factor calculation for Activity Effectiveness – Outage Program Risk, PSPS Consequence

$$b)\ weighting\ factor_i = \frac{mean(PSPS\ Conseq\ Component_i)}{mean(PSPS\ Consequence)}$$

The weighting factor for sub-driver, i, is defined as the average of the relevant (i.e., non-zero) PSPS Consequence Component, i, divided by the PSPS Consequence Components across all PSPS risk drivers.

Figure SCE 6-15: Activity Effectiveness – Outage Program Risk Calculation

$$Activity\ Effectiveness\ =\ \sum_{i=1}^{n} OP_i \cdot ME\%_i$$

The activity effectiveness – outage program risk is defined either as the sum of PSPS or the sum of PEDS risk sub-driver, i, weighting factors multiplied by the sub-driver, i, mitigation effectiveness values across all the sub-

100 For its calculation of PEDS, SCE assumed the same mitigation effectiveness on PEDS outage likelihood risk drivers as on wildfire risk drivers, resulting in similar activity effectiveness numbers for wildfire and PEDS-related outage program risk. For example, vegetation contact with an energized line could lead to an ignition but it also represents potential faults and outages.

drivers. For those mitigations whose sub-drivers are predominantly PSPS consequence, SCE uses equation (b). For PEDS mitigations, SCE uses equation (a).

Risk Spend Efficiency – Overall Risk

Figure SCE 6-16: Risk Spend Efficiency – Overall Risk Calculation

$$Overall\ Risk_{RSE} = \sum \frac{NPV\ (Benefits)}{NPV\ (Cost^{101})} \text{X } 10{,}000{,}000^{102}$$

The risk spend efficiency – overall risk is defined as the sum of the net present value of benefits divided by the sum of the net present value of costs multiplied by 10 million.

Risk Spend Efficiency - Wildfire Risk

Figure SCE 6-17: Risk Spend Efficiency – Wildfire Risk Calculation

$$Wildfire\ Risk_{RSE} = \sum \frac{NPV\ (Wildfire\ Benefits)}{NPV\ (Cost^{103})} \text{X } 10{,}000{,}000$$

The risk spend efficiency – wildfire risk is defined as the sum of the net present value of wildfire benefits divided by the sum of the net present value of costs multiplied by 10 million. SCE is unable to parse out the specific costs related to wildfire risk for various activities.

Risk Spend Efficiency – Outage Program Risk

Figure SCE 6-18: Risk Spend Efficiency – Outage Program Risk Calculation

$$Outage\ Program\ Risk_{RSE} = \sum \frac{NPV\ (Outage\ Program\ Benefits)}{NPV\ (Cost^{104})} \text{X } 10{,}000{,}000$$

The risk spend efficiency – outage program risk is defined as the sum of the net present value of outage program benefits divided by the sum of the net present value of costs multiplied by 10 million. SCE is unable to parse out the specific costs related to outage program risk for various activities.

% HFTD Covered[105]

Figure SCE 6-19: Percent of HFTD Covered Calculation

$$\%\ HFTD\ Covered\ = \frac{scoped\ units\ or\ miles}{total\ HFTD\ units\ or\ miles} \text{X } 100$$

The % HFTD covered is defined as the scoped activity units or miles over the three year WMP period divided by the total scoped activity HFTD units or miles multiplied by 100.

Expected % risk reduction

Figure SCE 6-20: Expected Percent Risk Reduction Calculation

$$Expected\ \%\ Risk\ Reduction\ = \frac{risk\ before^{106} - risk\ after}{risk\ before} \text{X } 100$$

The expected % risk reduction as defined as the risk at the beginning of the year (as of January 1) minus the risk after (defined below) divided by the risk at the beginning of the year (as of January 1). The result is multiplied by 100.

Risk After

Figure SCE 6-21 Risk After Calculation

$$Risk\ After = \text{risk before X } (1 - Activity\ Effectiveness\ \%)$$

Risk after is defined as risk at the beginning of the year (as of January 1) multiplied by 1 minus the activity effectiveness percentage.

101 Costs are calculated in thousands.
102 SCE uses a 10 million multiplier on its RSE scores to improve readability.
103 For this calculation, the costs of wildfire risk and overall risk are the same. SCE is unable to parse out the specific costs related to wildfire risk for various activities.
104 For this calculation, the costs of outage program risk and overall risk are the same. SCE is unable to parse out the specific costs related to outage program risk for various activities.
105 For IN and VM activities, focuses on number of inspected structures
106 "Risk before" refers to risk at the beginning of the year.

6.2.1.3 Projected Risk Reduction on Highest-Risk Circuits Over the Three-Year WMP Cycle

The objective of the service territory risk reduction summary is to provide an integrated view of wildfire risk reduction across the electrical corporation's service territory. The electrical corporation must provide the following information:

- *Tabular summary of numeric risk reduction for each high-risk circuit within the top 20- percent of overall utility risk, showing risk levels before and after the implementation of activities. This must include the same circuits, segments, or span IDs presented in Section 5.5.2. The table must include the following information for each circuit:*
- ***Circuit, Segment, or Span ID:** Unique identifier for the circuit, segment, or span.*
    - *If there are multiple activities per ID, each must be listed separately, using an extender to provide a unique identifier.*
- ***Overall Utility Risk:** Numerical value for the overall utility risk before and after each activity.*
- ***Activities by Implementation Year:** activities the electrical corporation plans to apply to the circuit in each year of the WMP cycle.*

Table 6-4 provides an example and required format of a summary of risk reduction for top-risk circuits.

Table 6-4 below shows SCE's circuits ranked by overall utility risk in HFRA using MARS. The existing risk as of January 1, 2026 takes into account covered conductor that was (or is expected to be) installed prior to 2026. Residual risk may remain high according to MARS for some circuits, even after covered conductor is installed, due to high potential consequence in those areas. SCE provides a more detailed description of the top-risk circuits below.

Table 6-4: SCE Summary of Risk Reduction for Top-Risk Circuits[107]

Circuit, Segment, or Span ID	Initial Overall Utility Risk	2026 Initiative Activities	2026 Overall Utility Risk	2027 Initiative Activities	2027 Overall Utility Risk	2028 Initiatives Activities	2028 Overall Utility Risk
TUNGSTEN	0.79861	Covered Conductor, Distribution HFRI Inspections and Remediations, Transmission HFRI Inspections and Remediations, Structure Brushing	0.79861	Distribution HFRI Inspections and Remediations, Transmission HFRI Inspections and Remediations, Structure Brushing	0.79861	Distribution HFRI Inspections and Remediations, Structure Brushing	0.79861
PHEASANT	3.18451	Distribution HFRI Inspections and Remediations, Hazard Tree Management Program, Structure Brushing, Dead and Dying Tree Removal	3.18451	Distribution HFRI Inspections and Remediations, Hazard Tree Management Program, Structure Brushing, Dead and Dying Tree Removal	3.18451	Distribution HFRI Inspections and Remediations, Hazard Tree Management Program, Structure Brushing, Dead and Dying Tree Removal	3.18451
LOUCKS	1.33272	Distribution HFRI Inspections and Remediations, Hazard Tree Management Program, Structure Brushing, Dead and Dying Tree Removal	1.33272	Distribution HFRI Inspections and Remediations, Hazard Tree Management Program, Structure Brushing, Dead and Dying Tree Removal	1.33272	Distribution HFRI Inspections and Remediations, Hazard Tree Management Program, Structure Brushing, Dead and Dying Tree Removal	1.33272
PASCAL	2.26526	Distribution HFRI Inspections and Remediations, Hazard Tree Management Program, Structure Brushing, Dead and Dying Tree Removal	2.26526	Distribution HFRI Inspections and Remediations, Hazard Tree Management Program, Structure Brushing, Dead and Dying Tree Removal	2.26526	Distribution HFRI Inspections and Remediations, Hazard Tree Management Program, Structure Brushing, Dead and Dying Tree Removal	2.26526
DAVENPORT	12.89816	Distribution HFRI Inspections and Remediations, Transmission HFRI Inspections and Remediations, Hazard Tree Management Program, Structure Brushing, Dead and Dying Tree Removal	12.89816	Distribution HFRI Inspections and Remediations, Transmission HFRI Inspections and Remediations, Hazard Tree Management Program, Structure Brushing, Dead and Dying Tree Removal	12.89816	Distribution HFRI Inspections and Remediations, Hazard Tree Management Program, Structure Brushing, Dead and Dying Tree Removal	12.89816
CERRITO	0.35024	Distribution HFRI Inspections and Remediations, Hazard Tree Management Program, Structure Brushing, Dead and Dying Tree Removal	0.35024	Distribution HFRI Inspections and Remediations, Hazard Tree Management Program, Structure Brushing, Dead and Dying Tree Removal	0.35024	Distribution HFRI Inspections and Remediations, Hazard Tree Management Program, Structure Brushing, Dead and Dying Tree Removal	0.35024
RAYBURN	2.11324	Distribution HFRI Inspections and Remediations, Transmission HFRI Inspections and Remediations, Hazard Tree Management Program, Structure Brushing, Dead and Dying Tree Removal	2.11324	Distribution HFRI Inspections and Remediations, Transmission HFRI Inspections and Remediations, Hazard Tree Management Program, Structure Brushing, Dead and Dying Tree Removal	2.11324	Distribution HFRI Inspections and Remediations, Transmission HFRI Inspections and Remediations, Transmission Infrared and Corona Scanning, Hazard Tree Management Program, Structure Brushing, Dead and Dying Tree Removal	2.11324
SHOVEL	8.09005	Distribution HFRI Inspections and Remediations, Hazard Tree Management Program, Structure Brushing, Dead and Dying Tree Removal	8.09005	Distribution HFRI Inspections and Remediations, Hazard Tree Management Program, Structure Brushing, Dead and Dying Tree Removal	8.09005	Distribution HFRI Inspections and Remediations, Hazard Tree Management Program, Structure Brushing, Dead and Dying Tree Removal	8.09005
PELONA	0.29890	Transmission Proactive Splice Shunting, Distribution HFRI Inspections and Remediations, Transmission HFRI Inspections and Remediations, Hazard Tree Management Program, Structure Brushing, Dead and Dying Tree Removal	0.29890	Distribution HFRI Inspections and Remediations, Transmission HFRI Inspections and Remediations, Hazard Tree Management Program, Structure Brushing, Dead and Dying Tree Removal	0.29890	Distribution HFRI Inspections and Remediations, Transmission Infrared and Corona Scanning, Hazard Tree Management Program, Structure Brushing, Dead and Dying Tree Removal	0.29890
GUFFY	0.78051	Distribution HFRI Inspections and Remediations, Hazard Tree Management	0.78051	Distribution HFRI Inspections and Remediations, Hazard Tree	0.78051	Distribution HFRI Inspections and Remediations, Hazard Tree Management	0.77738

107 Initial overall utility risk captures risk information as of 3/25/2025. 2026 Overall Risk, 2027 Overall Risk, and 2028 Overall Risk capture estimated risk information as of 12/31 of 2026, 2027, and 2028, respectively, based on forecasted deployment of mitigations presented in this WMP.

Circuit, Segment, or Span ID	Initial Overall Utility Risk	2026 Initiative Activities	2026 Overall Utility Risk	2027 Initiative Activities	2027 Overall Utility Risk	2028 Initiatives Activities	2028 Overall Utility Risk
		Program, Structure Brushing, Dead and Dying Tree Removal		Management Program, Structure Brushing, Dead and Dying Tree Removal		Program, Structure Brushing, Dead and Dying Tree Removal	
STORES	4.20072	Distribution HFRI Inspections and Remediations, Hazard Tree Management Program, Structure Brushing, Dead and Dying Tree Removal	4.20072	Distribution HFRI Inspections and Remediations, Hazard Tree Management Program, Structure Brushing, Dead and Dying Tree Removal	4.20072	Distribution HFRI Inspections and Remediations, Hazard Tree Management Program, Structure Brushing, Dead and Dying Tree Removal	4.20072
PURCHASE	0.56434	Distribution HFRI Inspections and Remediations, Hazard Tree Management Program, Structure Brushing, Dead and Dying Tree Removal	0.56434	Distribution HFRI Inspections and Remediations, Hazard Tree Management Program, Structure Brushing, Dead and Dying Tree Removal	0.56434	Distribution HFRI Inspections and Remediations, Hazard Tree Management Program, Structure Brushing, Dead and Dying Tree Removal	0.56434
ENERGY	4.45002	Distribution HFRI Inspections and Remediations, Transmission HFRI Inspections and Remediations, Hazard Tree Management Program, Structure Brushing, Dead and Dying Tree Removal	4.45002	Remote Controlled Automated Reclosers Settings Update, Distribution HFRI Inspections and Remediations, Transmission HFRI Inspections and Remediations, Hazard Tree Management Program, Structure Brushing, Dead and Dying Tree Removal	4.44978	Distribution HFRI Inspections and Remediations, Hazard Tree Management Program, Structure Brushing, Dead and Dying Tree Removal	4.44978
ARIEL	0.04900	Distribution HFRI Inspections and Remediations, Hazard Tree Management Program, Structure Brushing, Dead and Dying Tree Removal	0.04900	Distribution HFRI Inspections and Remediations, Hazard Tree Management Program, Structure Brushing, Dead and Dying Tree Removal	0.04900	Distribution HFRI Inspections and Remediations, Hazard Tree Management Program, Structure Brushing, Dead and Dying Tree Removal	0.04900
BODKIN	0.23424	Distribution HFRI Inspections and Remediations, Hazard Tree Management Program, Structure Brushing, Dead and Dying Tree Removal	0.23424	Distribution HFRI Inspections and Remediations, Hazard Tree Management Program, Structure Brushing, Dead and Dying Tree Removal	0.23424	Distribution HFRI Inspections and Remediations, Hazard Tree Management Program, Structure Brushing, Dead and Dying Tree Removal	0.23424
CASCADE	0.90370	Distribution HFRI Inspections and Remediations, Hazard Tree Management Program, Structure Brushing, Dead and Dying Tree Removal	0.90370	Distribution HFRI Inspections and Remediations, Hazard Tree Management Program, Structure Brushing, Dead and Dying Tree Removal	0.90370	Distribution HFRI Inspections and Remediations, Hazard Tree Management Program, Structure Brushing, Dead and Dying Tree Removal	0.90370
IDA	1.34631	Distribution HFRI Inspections and Remediations, Transmission HFRI Inspections and Remediations, Hazard Tree Management Program, Structure Brushing, Dead and Dying Tree Removal	1.34631	Distribution HFRI Inspections and Remediations, Transmission HFRI Inspections and Remediations, Hazard Tree Management Program, Structure Brushing, Dead and Dying Tree Removal	1.34631	Distribution HFRI Inspections and Remediations, Transmission Infrared and Corona Scanning, Hazard Tree Management Program, Structure Brushing, Dead and Dying Tree Removal	1.34631
FINGAL	4.53771	REFCL Ground Fault Neutralizer, Distribution HFRI Inspections and Remediations, Transmission HFRI Inspections and Remediations, Hazard Tree Management Program, Structure Brushing, Dead and Dying Tree Removal	2.28455	Distribution HFRI Inspections and Remediations, Transmission HFRI Inspections and Remediations, Hazard Tree Management Program, Structure Brushing, Dead and Dying Tree Removal	2.28455	Distribution HFRI Inspections and Remediations, Hazard Tree Management Program, Structure Brushing, Dead and Dying Tree Removal	2.28455
POPPET FLATS	4.01514	REFCL Ground Fault Neutralizer, Distribution HFRI Inspections and Remediations, Transmission HFRI Inspections and Remediations, Hazard Tree Management Program, Structure Brushing, Dead and Dying Tree Removal	2.18252	Distribution HFRI Inspections and Remediations, Transmission HFRI Inspections and Remediations, Hazard Tree Management Program, Structure Brushing, Dead and Dying Tree Removal	2.18252	Distribution HFRI Inspections and Remediations, Hazard Tree Management Program, Structure Brushing, Dead and Dying Tree Removal	2.18252
STONEMAN	3.19270	Long Span Initiative, Distribution HFRI Inspections and Remediations, Distribution	3.19218	Long Span Initiative, Distribution HFRI Inspections and	3.19217	Distribution HFRI Inspections and Remediations, Hazard Tree	3.19216

Circuit, Segment, or Span ID	Initial Overall Utility Risk	2026 Initiative Activities	2026 Overall Utility Risk	2027 Initiative Activities	2027 Overall Utility Risk	2028 Initiatives Activities	2028 Overall Utility Risk
		Infrared Scanning, Hazard Tree Management Program, Structure Brushing, Dead and Dying Tree Removal		Remediations, Hazard Tree Management Program, Structure Brushing, Dead and Dying Tree Removal		Management Program, Structure Brushing, Dead and Dying Tree Removal	
PIONEERTOWN	6.78102	Covered Conductor, REFCL Ground Fault Neutralizer, Distribution HFRI Inspections and Remediations, Hazard Tree Management Program, Structure Brushing, Dead and Dying Tree Removal	2.98328	Distribution HFRI Inspections and Remediations, Hazard Tree Management Program, Structure Brushing, Dead and Dying Tree Removal	2.98328	Distribution HFRI Inspections and Remediations, Structure Brushing	2.98328
PICK [1]	4.48935	Distribution HFRI Inspections and Remediations, Transmission HFRI Inspections and Remediations, Hazard Tree Management Program, Structure Brushing, Dead and Dying Tree Removal	4.48935	Distribution HFRI Inspections and Remediations, Transmission HFRI Inspections and Remediations, Hazard Tree Management Program, Structure Brushing, Dead and Dying Tree Removal	4.48935	Distribution HFRI Inspections and Remediations, Hazard Tree Management Program, Structure Brushing, Dead and Dying Tree Removal	4.48935
IRVINGTON	0.02587	Distribution HFRI Inspections and Remediations, Structure Brushing	0.02587	Distribution HFRI Inspections and Remediations, Structure Brushing	0.02515	Distribution HFRI Inspections and Remediations, Structure Brushing	0.02515
PICONI	1.99738	Distribution HFRI Inspections and Remediations, Transmission HFRI Inspections and Remediations, Hazard Tree Management Program, Structure Brushing, Dead and Dying Tree Removal	1.99738	Distribution HFRI Inspections and Remediations, Transmission HFRI Inspections and Remediations, Transmission Infrared and Corona Scanning, Hazard Tree Management Program, Structure Brushing, Dead and Dying Tree Removal	1.99738	Distribution HFRI Inspections and Remediations, Transmission HFRI Inspections and Remediations, Hazard Tree Management Program, Structure Brushing, Dead and Dying Tree Removal	1.99737
SNOWCREEK	0.17684	Distribution HFRI Inspections and Remediations, Hazard Tree Management Program, Structure Brushing, Dead and Dying Tree Removal	0.17684	Distribution HFRI Inspections and Remediations, Hazard Tree Management Program, Structure Brushing, Dead and Dying Tree Removal	0.17684	Distribution HFRI Inspections and Remediations, Hazard Tree Management Program, Structure Brushing, Dead and Dying Tree Removal	0.17684
NUTMEG	0.77035	Distribution HFRI Inspections and Remediations, Transmission HFRI Inspections and Remediations, Hazard Tree Management Program, Structure Brushing, Dead and Dying Tree Removal	0.77035	Distribution HFRI Inspections and Remediations, Transmission HFRI Inspections and Remediations, Hazard Tree Management Program, Structure Brushing, Dead and Dying Tree Removal	0.77035	Distribution HFRI Inspections and Remediations, Hazard Tree Management Program, Structure Brushing, Dead and Dying Tree Removal	0.77035
SCHMIDT	1.44596	Distribution HFRI Inspections and Remediations, Transmission HFRI Inspections and Remediations, Transmission Infrared and Corona Scanning, Hazard Tree Management Program, Structure Brushing, Dead and Dying Tree Removal	1.44596	Distribution HFRI Inspections and Remediations, Transmission HFRI Inspections and Remediations, Hazard Tree Management Program, Structure Brushing, Dead and Dying Tree Removal	1.44596	Distribution HFRI Inspections and Remediations, Transmission Infrared and Corona Scanning, Hazard Tree Management Program, Structure Brushing, Dead and Dying Tree Removal	1.44173
SEAWOLF	0.09392	Distribution HFRI Inspections and Remediations, Structure Brushing	0.09392	Distribution HFRI Inspections and Remediations, Structure Brushing	0.09392	Distribution HFRI Inspections and Remediations, Hazard Tree Management Program, Structure Brushing, Dead and Dying Tree Removal	0.09392
ARAPAHO	1.45272	Distribution HFRI Inspections and Remediations, Distribution Infrared Scanning, Hazard Tree Management Program, Structure Brushing, Dead and Dying Tree Removal	1.45272	Distribution HFRI Inspections and Remediations, Hazard Tree Management Program, Structure Brushing, Dead and Dying Tree Removal	1.45272	Distribution HFRI Inspections and Remediations, Hazard Tree Management Program, Structure Brushing, Dead and Dying Tree Removal	1.45272
MOAB	0.04860	Distribution HFRI Inspections and Remediations, Structure Brushing	0.04860	Distribution HFRI Inspections and Remediations, Structure Brushing	0.04860	Distribution HFRI Inspections and Remediations, Structure Brushing	0.0486

Circuit, Segment, or Span ID	Initial Overall Utility Risk	2026 Initiative Activities	2026 Overall Utility Risk	2027 Initiative Activities	2027 Overall Utility Risk	2028 Initiatives Activities	2028 Overall Utility Risk
LUISENO	2.60530	Distribution HFRI Inspections and Remediations, Transmission HFRI Inspections and Remediations, Hazard Tree Management Program, Structure Brushing, Dead and Dying Tree Removal	2.60530	Distribution HFRI Inspections and Remediations, Transmission HFRI Inspections and Remediations, Hazard Tree Management Program, Structure Brushing, Dead and Dying Tree Removal	2.60530	Distribution HFRI Inspections and Remediations, Hazard Tree Management Program, Structure Brushing, Dead and Dying Tree Removal	2.60530
BALLOON	0.35909	Distribution HFRI Inspections and Remediations, Distribution Infrared Scanning, Hazard Tree Management Program, Structure Brushing, Dead and Dying Tree Removal	0.35909	Distribution HFRI Inspections and Remediations, Hazard Tree Management Program, Structure Brushing, Dead and Dying Tree Removal	0.35909	Distribution HFRI Inspections and Remediations, Hazard Tree Management Program, Structure Brushing, Dead and Dying Tree Removal	0.35909
BOUQUET	2.09672	Transmission Proactive Splice Shunting, Distribution HFRI Inspections and Remediations, Transmission HFRI Inspections and Remediations, Transmission Infrared and Corona Scanning, Hazard Tree Management Program, Structure Brushing, Dead and Dying Tree Removal	2.09662	Distribution HFRI Inspections and Remediations, Transmission HFRI Inspections and Remediations, Hazard Tree Management Program, Structure Brushing, Dead and Dying Tree Removal	2.09662	Distribution HFRI Inspections and Remediations, Hazard Tree Management Program, Structure Brushing, Dead and Dying Tree Removal	2.09662
CALSPAR	0.02751	Long Span Initiative, Distribution HFRI Inspections and Remediations, Distribution Infrared Scanning, Structure Brushing	0.02746	Distribution HFRI Inspections and Remediations, Hazard Tree Management Program, Structure Brushing, Dead and Dying Tree Removal	0.02746	Distribution HFRI Inspections and Remediations, Structure Brushing	0.02305
BIG ROCK	1.17538	Remote Controlled Automated Reclosers Settings Update, Distribution HFRI Inspections and Remediations, Transmission HFRI Inspections and Remediations, Distribution Infrared Scanning, Hazard Tree Management Program, Structure Brushing, Dead and Dying Tree Removal	1.17538	Long Span Initiative, Distribution HFRI Inspections and Remediations, Transmission HFRI Inspections and Remediations, Hazard Tree Management Program, Structure Brushing, Dead and Dying Tree Removal	1.17537	Distribution HFRI Inspections and Remediations, Hazard Tree Management Program, Structure Brushing, Dead and Dying Tree Removal	1.17505
STAR ROCK	0.19825	Remote Controlled Automated Reclosers Settings Update, Distribution HFRI Inspections and Remediations, Structure Brushing	0.19825	Distribution HFRI Inspections and Remediations, Hazard Tree Management Program, Structure Brushing, Dead and Dying Tree Removal	0.19820	Distribution HFRI Inspections and Remediations, Structure Brushing	0.19820
KELLER	0.08733	Distribution HFRI Inspections and Remediations, Transmission HFRI Inspections and Remediations, Structure Brushing	0.08733	Distribution HFRI Inspections and Remediations, Structure Brushing	0.08733	Distribution HFRI Inspections and Remediations, Transmission Infrared and Corona Scanning, Hazard Tree Management Program, Structure Brushing, Dead and Dying Tree Removal	0.08733
CORTESE	0.17324	Distribution HFRI Inspections and Remediations, Transmission HFRI Inspections and Remediations, Hazard Tree Management Program, Structure Brushing, Dead and Dying Tree Removal	0.17324	Distribution HFRI Inspections and Remediations, Transmission HFRI Inspections and Remediations, Transmission Infrared and Corona Scanning, Hazard Tree Management Program, Structure Brushing, Dead and Dying Tree Removal	0.17324	Undergrounding Overhead Conductor, Distribution HFRI Inspections and Remediations, Hazard Tree Management Program, Structure Brushing, Dead and Dying Tree Removal	0.04319
BOOTLEGGER	6.45075	Distribution HFRI Inspections and Remediations, Hazard Tree Management Program, Structure Brushing, Dead and Dying Tree Removal	6.45075	Distribution HFRI Inspections and Remediations, Hazard Tree Management Program, Structure Brushing, Dead and Dying Tree Removal	6.45075	Distribution HFRI Inspections and Remediations, Hazard Tree Management Program, Structure Brushing, Dead and Dying Tree Removal	6.45075

Circuit, Segment, or Span ID	Initial Overall Utility Risk	2026 Initiative Activities	2026 Overall Utility Risk	2027 Initiative Activities	2027 Overall Utility Risk	2028 Initiatives Activities	2028 Overall Utility Risk
UTE	0.08064	Long Span Initiative, Distribution HFRI Inspections and Remediations, Hazard Tree Management Program, Structure Brushing, Dead and Dying Tree Removal	0.07956	Distribution HFRI Inspections and Remediations, Hazard Tree Management Program, Structure Brushing, Dead and Dying Tree Removal	0.07956	Distribution HFRI Inspections and Remediations, Hazard Tree Management Program, Structure Brushing, Dead and Dying Tree Removal	0.07956
SOUTHRIDGE	0.03865	Distribution HFRI Inspections and Remediations, Structure Brushing	0.03865	Distribution HFRI Inspections and Remediations, Hazard Tree Management Program, Structure Brushing, Dead and Dying Tree Removal	0.03569	Covered Conductor, Distribution HFRI Inspections and Remediations, Structure Brushing	0.03569
MOCKINGBIRD	0.56335	Distribution HFRI Inspections and Remediations, Transmission HFRI Inspections and Remediations, Hazard Tree Management Program, Structure Brushing, Dead and Dying Tree Removal	0.56335	Distribution HFRI Inspections and Remediations, Transmission HFRI Inspections and Remediations, Hazard Tree Management Program, Structure Brushing, Dead and Dying Tree Removal	0.56335	Distribution HFRI Inspections and Remediations, Hazard Tree Management Program, Structure Brushing, Dead and Dying Tree Removal	0.56335
CORONITA	0.03590	Distribution HFRI Inspections and Remediations, Structure Brushing	0.03590	Distribution HFRI Inspections and Remediations, Structure Brushing	0.03590	Distribution HFRI Inspections and Remediations, Structure Brushing	0.03590
ATENTO	2.07503	Distribution HFRI Inspections and Remediations, Hazard Tree Management Program, Structure Brushing, Dead and Dying Tree Removal	2.07503	Distribution HFRI Inspections and Remediations, Hazard Tree Management Program, Structure Brushing, Dead and Dying Tree Removal	2.07503	Distribution HFRI Inspections and Remediations, Hazard Tree Management Program, Structure Brushing, Dead and Dying Tree Removal	2.07503
PAWNEE	4.22999	Distribution HFRI Inspections and Remediations, Hazard Tree Management Program, Structure Brushing, Dead and Dying Tree Removal	4.22999	Distribution HFRI Inspections and Remediations, Hazard Tree Management Program, Structure Brushing, Dead and Dying Tree Removal	4.22999	Distribution HFRI Inspections and Remediations, Hazard Tree Management Program, Structure Brushing, Dead and Dying Tree Removal	4.22999
INYO LUMBER	0.24229	Distribution HFRI Inspections and Remediations, Hazard Tree Management Program, Structure Brushing, Dead and Dying Tree Removal	0.24229	Distribution HFRI Inspections and Remediations, Hazard Tree Management Program, Structure Brushing, Dead and Dying Tree Removal	0.24229	Distribution HFRI Inspections and Remediations, Hazard Tree Management Program, Structure Brushing, Dead and Dying Tree Removal	0.24229
PARADISE	1.12261	Undergrounding Overhead Conductor, Long Span Initiative, Transmission Proactive Splice Shunting, Distribution HFRI Inspections and Remediations, Transmission HFRI Inspections and Remediations, Distribution Infrared Scanning, Hazard Tree Management Program, Structure Brushing, Dead and Dying Tree Removal	0.28051	Undergrounding Overhead Conductor, Long Span Initiative, Distribution HFRI Inspections and Remediations, Transmission HFRI Inspections and Remediations, Hazard Tree Management Program, Structure Brushing, Dead and Dying Tree Removal	0.24101	Distribution HFRI Inspections and Remediations, Transmission Infrared and Corona Scanning, Hazard Tree Management Program, Structure Brushing, Dead and Dying Tree Removal	0.24101
PERRIS	0.25347	Distribution HFRI Inspections and Remediations, Hazard Tree Management Program, Structure Brushing, Dead and Dying Tree Removal	0.25347	Distribution HFRI Inspections and Remediations, Hazard Tree Management Program, Structure Brushing, Dead and Dying Tree Removal	0.25347	Distribution HFRI Inspections and Remediations, Structure Brushing	0.25347
RAMSGATE	0.06834	Distribution HFRI Inspections and Remediations, Hazard Tree Management Program, Structure Brushing, Dead and Dying Tree Removal	0.06834	Distribution HFRI Inspections and Remediations, Hazard Tree Management Program, Structure Brushing, Dead and Dying Tree Removal	0.06834	Distribution HFRI Inspections and Remediations, Hazard Tree Management Program, Structure Brushing, Dead and Dying Tree Removal	0.06834

[1] This circuit is located in the burn scar area of the Lidia Fire in January 2025.

6.2.2 Interim Activities

For each activity that will require more than one year to implement, the electrical corporation must evaluate the need for interim activities that will reduce risk until the primary or permanent activity is in place. In this section of its WMP, the electrical corporation must provide a description of the following:

- *The electrical corporation's procedures for evaluating the need for interim risk reduction. If an electrical corporation determines that interim activities are not necessary for a given activity, it must explain why and how it is monitoring wildfire and PSPS risk while working to implement the activity*
- *The electrical corporation's procedures for determining which interim activities to implement.*
- *The electrical corporation's characterization of each interim initiative activity and evaluation of its specific capabilities to reduce risks, including:*
  - *Potential consequences of risk event(s) addressed by the improvement/activity.*
  - *Frequency of occurrence of the risk event(s) addressed by the improvement/activity.*
- *The electrical corporation's procedures for evaluating and implementing any changes in initiative effectiveness and prioritization based on time for implementation and use of interim activities, including:*
  - *The cumulative risk exposure of its activity portfolio, accounting for the time value of risk as part of activity comparisons.*

Each interim activity planned by the electrical corporation for implementation on high-risk circuits must be listed as an activity in Sections 8-12. In addition, the electrical corporation must discuss interim activities in the relevant mitigation initiative (initiative) sections of the WMP and include the activities in the related target tables.

SCE's approach to interim mitigations is based on two considerations. The first is the known risks on the circuit segment (e.g., long spans at heightened risk of wire-to-wire contact, heavy trees within range of SCE's facilities, etc.). The second is the current expected timeframe for the permanent mitigations to be deployed on the system. Generally speaking, the primary mitigation initiatives that require interim mitigation strategies due to their lead times are covered conductor and undergrounding, both of which are explained further below.

SCE deploys one interim mitigation, Long Span Initiative (SH-14), as local conditions require, on segments that will be hardened with covered conductor.

This initiative installs line spacers on segments that are at heightened risk of wire-to-wire contact. SCE can implement this remediation relatively quickly, making it an effective interim mitigation option to reduce risk on overhead lines that are especially subject to this risk driver. Please see 8.2.5.1 for more details on LSI.

In addition to the above interim mitigation, SCE will also implement complementary mitigations, as local conditions require, prior to the installation of covered conductor. Mitigations including asset inspections, vegetation management, and fast curve settings, which will mitigate contact from object, wire-to-wire contact, and equipment failure risk drivers on the circuit segment before covered conductor is installed. In some cases, based on local conditions, SCE may perform additional inspections or vegetation management inspections as part of its AOC effort. However, unlike LSI, SCE will continue using these mitigations on the circuit segment after covered conductor is installed. They complement covered conductor by either addressing risk drivers that covered conductor does not address or by adding an extra layer of defense on risk drivers that covered conductor does address.

SCE deploys three interim mitigations on segments that will be hardened with undergrounding. These mitigations will cease in their current form after overhead lines are replaced with underground lines:

1. Long-Span Initiative (SH-14): See comments above.
2. SCE's asset inspection portfolio (e.g., 360-degree inspections and Infrared), which reduces ignitions caused by overhead equipment failures.
3. SCE's vegetation management portfolio (e.g., expanded line clearing, Hazard Tree Mitigation Program, etc.) reduces ignitions caused by vegetation contacting overhead facilities.

SCE will also use, if necessary, PSPS in locations that are scoped for undergrounding or covered conductor. Until such time as SCE installs covered conductor or undergrounding, SCE will use lower wind speed thresholds for bare-conductor isolatable segments. After installation of covered conductor or undergrounding, SCE will either raise de-energization thresholds or, in cases where a segment and its feeder are undergrounded, not use PSPS. Further details can be found in Sections 8.1.2 and 9.

7 PUBLIC SAFETY POWER SHUTOFF

7.1 Planned Initiative Actions to Reduce the Impacts of PSPS Events

In this section, the electrical corporation must provide an overview narrative of planned initiative actions to reduce the impacts of PSPS events. Impacts include:

- *Duration*
- *Frequency*
- *Scope – number of customers*

Proactive de-energization of power lines to reduce risk of wildfire, also known as Public Safety Power Shutoffs (PSPS), remains an important tool in protecting public safety and mitigating wildfire risk under dangerously high winds, low humidity, and dry vegetation conditions. PSPS is a protocol that SCE may implement in order to proactively interrupt service on a given circuit during extreme and/or potentially dangerous weather conditions.

SCE recognizes that turning off the power to its customers is a large burden for them and it is not something we take lightly. The objectives of SCE's PSPS program are to protect public safety while striving to keep the power on for as many customers as possible; communicate effectively and accurately before, during, and after events; and minimize the impact of de-energization through customer programs. PSPS remains SCE's tool of last resort for mitigating wildfires.

The impacts of PSPS discussed in the guidance for this section – duration, frequency, and number of customers in scope for an event – are highly dependent on weather and fuel conditions, which are not within SCE's control. However, SCE makes every effort to mitigate the impacts of PSPS for its customers and public safety partners by enhancing the measures that are in our control. Because PSPS is SCE's tool of last resort for wildfire mitigation, the primary way to mitigate its use is to enhance other wildfire mitigation methods so that we do not have to implement our tool of last resort as frequently. This includes, but is not limited to, grid hardening activities, enhanced weather forecasting, and situational awareness capabilities. These measures can also help to mitigate the duration and scope of PSPS events when they do occur.

Below, SCE identifies wildfire mitigation measures discussed in other sections of this WMP that have the potential to notably mitigate PSPS impacts and describes how we expect them to mitigate the duration, frequency, and number of customers in scope for PSPS events during the 2026-2028 timeframe:

- **Covered Conductor** (Section 8.2.1) – For a circuit or circuit segment that is entirely covered conductor, the sustained wind speed and wind gust thresholds for de-energization are increased. SCE's goal to deploy 440 miles of covered conductor in the 2026-2028 period should mitigate the frequency and duration of PSPS events, depending on future weather, fuel, and moisture conditions.

- **Undergrounding of Electric Lines and/or Equipment** (Section 8.2.2) – PSPS outage risk is eliminated for fully underground circuits, assuming there is no upstream overhead circuitry in HFRA.[108] Undergrounding, therefore, greatly mitigates the frequency of PSPS events. SCE's goal to convert 260 miles of bare overhead distribution lines to underground lines in the 2026-2028 period will help limit PSPS events in its service territory. In addition, SCE is piloting alternative undergrounding technologies (Section 8.2.2.2) that can be installed at ground level and hence offer a less complex installation process than traditional undergrounding. As this is a pilot, outage risk mitigation effectiveness has not been calculated, but SCE is hopeful that alternative approaches to undergrounding can have similar impacts as traditional undergrounding in terms of reducing the risk of PSPS and other outages.
- **Remote Automatic Reclosers (RARs) and Remote Control Switches (RCS)** (Section 8.2.8) – RARs and RCSs allow SCE to sectionalize circuits into smaller segments during PSPS events. This enables SCE to mitigate the scope (i.e., number of customers) of PSPS events. Sectionalization can also have duration benefits because the number of circuit miles to assess prior to re-energization is reduced. SCE will continue to optimize its sectionalization in the 2026-2028 timeframe to mitigate impacts of PSPS events.
- **Weather Stations** (Section 10.2.1) – Weather stations provide critical situational awareness for PSPS decision-making. Weather conditions can differ significantly at any given time within the HFRA of SCE's service territory, due to the large size and diverse topography. Granular, circuit-level or circuit-segment-level weather data is used by incident management team (IMT) personnel to inform initiation of PSPS events, customer notifications, de-energization decisions for SCE circuits, and re-energizations. Because weather station data can help IMT personnel determine whether to limit a PSPS event to certain segments of a circuit, they help to mitigate the scope and duration of PSPS events.
- **Live Field Observations (LFOs)** (Section 10.2.1) – During a PSPS event, SCE may deploy qualified personnel to high-risk portions of the grid to take live wind readings using handheld weather stations to supplement information from fixed weather stations and to watch for other imminent hazards. For circuits that are in scope, SCE conducts pre-patrols to visually inspect the entire length of each circuit or circuit segment to find any imminent hazards or equipment vulnerabilities that require immediate remediation and to provide additional intelligence on field conditions. If concerns are discovered on a circuit in scope, they are addressed before the impending wind event, if possible. These LFOs are performed to provide

108 Isolatable circuit segments that are connected to upstream OH circuits can still experience PSPS outages if there is no way to reroute them to get power from another non-PSPS impacted circuit.

real-time data to SCE's Emergency Operations Center. After concerning weather conditions have abated, SCE dispatches qualified personnel again to perform restoration patrols on all circuits that experienced a PSPS de-energization to ensure that they are safe for service restoration. These protocols are imperative to SCE's decision making and will continue to be a part of SCE's WMP for the foreseeable future.

- **Weather Forecasting** (Section 10.5) – SCE's weather forecasting capabilities enable us to anticipate when PSPS events and de-energizations may be needed. In the 2026 to 2028 WMP cycle, SCE will focus on maintaining and refining existing capabilities for improved accuracy, as well as continuing to evaluate new and emerging technologies for potential implementation.

In addition to mitigating the duration, frequency, and number of customers in scope for a PSPS event, SCE also tries to mitigate other impacts to those customers who are affected by a PSPS event – by being on a circuit or circuit segment that either has the potential to be de-energized or that actually is de-energized. Below, SCE identifies wildfire mitigation measures discussed in other sections of this WMP that have the potential to notably mitigate impacts other than duration, frequency, and scope for customers that experience a PSPS event:

- **Public Communication, Outreach, and Educational Awareness** (Section 11.4) – SCE has extensive protocols and processes for communicating with customers and public safety partners during PSPS events (as well as other emergencies). These procedures help customers and stakeholders stay informed and aware of impacts and potential impacts to SCE's electric service as well as measures available to support them if they are affected.
- **Customer Support in Wildfire and PSPS Emergencies** (Section 11.5) – SCE provides temporary backup generators to select customers, not only during PSPS events but also during maintenance outages necessary for implementing our WMP. We are committed to expanding successful customer program offerings, with a particular focus on customers with Access and Functional Needs (AFN) who rely on medical devices or assistive technology for their independence, health, or safety during PSPS de-energizations. During PSPS events, SCE provides support to customers through its Community Resource Centers (CRCs) and Community Crew Vehicles (CCVs). These locations provide resources such as water, snacks, access to restrooms, Wi-Fi, mobile phone charging, and updated outage information. We provide additional support to Medical Baseline customers who reside in HFRA through our Critical Care Battery Backup (CCBB) Program, which provides free portable backup batteries to eligible customers. For our customers with AFN, SCE offers its Disability Disaster and Access Resource (DDAR) Program to provide support before and during PSPS events. SCE also offers its Portable Power Station Rebate Program and Portable Generator Rebate Program to all customers living in HFRA. SCE is piloting additional customer support efforts during PSPS events such as the In-Event Battery Loan Pilot.

In addition, SCE has been and continues to optimize its reliance on automation to streamline management of PSPS events and improve the accuracy and speed of notifications to customers and other stakeholders.

7.2 Frequently De-Energized Circuits

The narrative must summarize how the electrical corporation will reduce the need for, and impact of, future PSPS implementation on circuits that have been frequently deenergized, as listed in Table 4-3 in Section 4.3.

Table 4-3 in Section 4.3 (the fully populated version of the table is in Appendix F) identifies SCE's 92 "Frequently De-energized Circuits," which are defined as circuits that have had three or more PSPS events per calendar year.

SCE has already implemented several of the mitigation measures described in Section 7.1 to mitigate the impacts of PSPS events on these circuits. This includes:

- **Covered Conductor***:* SCE has installed nearly 1,000 miles of insulated conductor on 69 of the circuits.
- **RARs and RCS:** SCE has upgraded or installed more than 30 automated switches on more than 20 circuits.
- **Weather Stations:** SCE has installed new weather stations to improve situational awareness for 13 of the circuits.

In addition, SCE has implemented PSPS protocols to raise the PSPS windspeed thresholds for nine of the circuits based on new covered conductor installation and some exceptions for bare conductor circuits with minimal risk. SCE has also updated switching protocols to enable customer load to be transferred to adjacent circuits for twelve of the Frequently De-Energized Circuits.

To further reduce the need for, and impact of, future PSPS events on these circuits, SCE will implement the following mitigation measures during the 2026-2028 timeframe to try to reduce the frequency, duration, and scope of PSPS events on the Frequently De-Energized Circuits:

- **Covered Conductor***:* SCE plans to install nearly 80 miles of insulated conductor on 12 circuits.
- **RARs and RCS***:* Upgrade or install six automated switches on five circuits.

SCE expects to implement additional circuit segmentation. In addition, 22 circuits are undergoing engineering review to determine potential PSPS grid hardening measures.

7.3 Lessons Learned Since 2023-2025 WMP

Furthermore, the narrative should describe any lessons learned for PSPS events occurring since the electrical corporation's last WMP submission and overall impacts to mitigation methodology in terms of reducing PSPS events in the future.

Below, SCE describes lessons it has learned for PSPS events since the submission of its 2023-2025 WMP. In addition, in light of the January 2025 extreme weather conditions and wildfires that left many customers without power for an extended period of time, SCE is re-evaluating its customer support programs to enhance and better support customers during extreme events and will report any relevant findings and lessons learned in future WMP updates.

- **Use of field wind meters in LFOs:** Live Field Observers can use field wind meters that provide more granular wind speed data for the specific locations and heights of SCE assets. This technology more efficiently and accurately logs observation data into Survey 123, which is relayed back to IMT personnel for decision-making. LFOs use Bluetooth-enabled Kestrel wind meters. The meters can be attached to a hot stick (an insulated pole used by utility workers to work on or near energized equipment) to provide readings higher up from the ground. While this is not a new lesson learned since the last WMP, it has been reinforced during the 2023-2025 WMP period because it helps SCE to make more targeted PSPS de-energization decisions.
- **Missed Customer Notifications:** The 2023 and 2024 PSPS seasons had PSPS events in which SCE experienced a high volume of missed notifications. Some of the missed notifications were due to emergent weather that resulted in SCE de-energizing without enough time to send notifications within the required timeframe. To improve its notifications during a PSPS event, SCE is expanding its machine learning modeling capabilities to enhance forecast accuracy with the goal of being able to more precisely predict when and where PSPS thresholds might be met so that appropriate notifications can be sent to customers in the required timeframes. Because weather forecasting remains inherently uncertain, particularly at a granular level, SCE may not be able to avoid these types of missed notifications completely, but we hope to greatly reduce them. Improved success rate of notifications will not affect the duration, frequency, or scope impacts of PSPS events, but it can improve the experience for a customer that is subject to a PSPS event.
- **Enhanced Customer Outreach:** Through its community engagement efforts, SCE received feedback that we should expand our marketing/outreach to better promote meetings and to have more refined messaging and more channels. As a result, SCE is working to expand its PSPS-related outreach to additional social media platforms. SCE continues to explore automation to improve notification performance. Improved communications will not affect the duration, frequency, or scope impacts of PSPS events, but it can improve the experience for a customer that is subject to a PSPS event.
- **LiDAR not useful for PSPS decision-making:** Through San Jose State University's Wind Profiler Project, in 2023 SCE piloted a project to consider whether it could use LiDAR to accurately predict surface-level winds during PSPS events. SCE determined that the effort was not worth pursuing due to data transfer times and

the more significant impact of using real-time profiling. SCE does not expect this to affect mitigation of PSPS impacts.

In addition, SCE uses after-action reports from PSPS exercises and events to make updates, if necessary, to our PSPS training and exercises based on lessons learned in the reports. In 2025, SCE plans to conduct a PSPS Full-Scale Exercise to address lessons learned from the 2024 season.

8 Grid Design, Operations, and Maintenance

Each electrical corporation's WMP must include plans for grid design, operations, and maintenance programmatic areas.

8.1 Targets

In this section, the electrical corporation must provide qualitative and quantitative targets for each year of the three-year WMP cycle. The electrical corporation must provide at least one qualitative or quantitative target for the following initiatives:

- *Grid Design and System Hardening (Section 8.2)*
- *Asset Inspections (Section 8.3)*
- *Equipment Maintenance and Repair (Section 8.4)*
- *Work Orders (Section 8.6)*
- *Grid Operations and Procedures (Section 8.7)*
- *Workforce Planning (Section 8.8)*

Quantitative targets are required for Quality Assurance (QA) and Quality Control (QC). See Section 8.5, for detailed quantitative target requirements for QA and QC. Reporting of QA and QC quantitative targets is only required in section 8.5.

8.1.1 Qualitative Targets

The electrical corporation must provide qualitative targets for its three-year plan for implementing and improving its grid design, operations, and maintenance, including the following:

- *Identification of which initiative(s) and activity/activities in the WMP the electrical corporation is implementing to achieve the stated target, including Tracking IDs and the Tracking ID(s) used in past WMPs ("Previous Tracking ID"), if applicable.*
- *A target completion date.*
- *Reference(s) to the WMP section(s) or appendix, including page numbers, where the details of the target(s) are documented and substantiated.*
- *This information must be provided in Table 8-1 below.*

8.1.2 Quantitative Targets

The electrical corporation must list all quantitative targets it will use to track progress on its grid design, operations, and maintenance in its three-year plan, broken out by each year of the WMP cycle. Electrical corporations will show progress toward completing quantitative targets in subsequent reports, including data submissions and WMP Updates. For each target, the electrical corporation must provide the following:

- *Identification of which initiative(s) and activity/activities in the WMP the electrical corporation is implementing to achieve the stated target, including Tracking IDs and the Tracking ID(s) used in past WMPs ("Previous Tracking ID"), if applicable*
- *Projected targets and totals for each of the three years of the WMP cycle and relevant units for the targets*
- *The percentage of each activity planned to be performed within HFTD and HFRA (if applicable)*
- *The expected % risk reduction for each of the three years of the WMP cycle.*[109]

The electrical corporation's quantitative targets must provide enough detail to effectively inform efforts to improve the performance of the electrical corporation's grid design, operations, and maintenance initiatives. Each activity must have distinct, trackable targets associated with the activity, even if the electrical corporation tracks targets internally with activities combined. Only inspection-related activities are required to have quarterly targets, with all other activities only requiring end of year total targets. At its discretion, the electrical corporation may provide further granularity as available.

Table 8-1 below provides examples of the minimum acceptable level of information.

109 The expected % risk reduction is the expected percentage risk reduction per year, as described in Section 6.2.1.2

Table 8-1: SCE Grid Design, Operation, and Maintenance Targets by year

Initiative	Quantitative or Qualitative Target	Activity (Tracking ID #)	Previous Tracking ID (if applicable)	Target Unit	2026 Target / Status [1]	% Planned in HFTD [2] for 2026	% Planned in HFRA for 2026	% Risk Reduction for 2026	2027 Target / Status [1]	% Planned in HFTD [2] for 2027	% Planned in HFRA for 2027	% Risk Reduction for 2027	2028 Target / Status [1]	% Planned in HFTD [2] for 2028	% Planned in HFRA for 2028	% Risk Reduction for 2028	Three-Year Total	Section; Page number
8.2 Grid Design & System Hardening	Quantitative	Covered Conductor (SH-1)	SH-1	Circuit Miles	Install 240 circuit miles of covered conductor, subject to resource/external constraints and other execution risks	100%	N/A	0.27%	Install 125 circuit miles of covered conductor, subject to resource/external constraints and other execution risks	100%	N/A	0.06%	Install 75 circuit miles of covered conductor, subject to resource/external constraints and other execution risks	100%	N/A	0.13%	440	8.2; p. 222
8.2 Grid Design & System Hardening	Quantitative	Undergrounding Overhead Conductor in HFRA (SH-2)	SH-2	OH circuit miles converted to UG	Convert 75 circuit miles of overhead to underground in SCE's HFRA, subject to resource/external constraints and other execution risks	100%	N/A	0.61%	Convert 100 circuit miles of overhead to underground in SCE's HFRA, subject to resource/external constraints and other execution risks	100%	N/A	0.92%	Convert 85 circuit miles of overhead to underground in SCE's HFRA, subject to resource/external constraints and other execution risks	100%	N/A	0.40%	260	8.2; p. 222
8.2 Grid Design & System Hardening	Quantitative	FR Wrap Expanded Deployment (SH-19)	SH-19	FR Wraps	Deploy fire-resistant wraps on 1,000 unprotected wood poles, subject to resource/external constraints and other execution risks	100%	N/A	0.0004%	Deploy fire-resistant wraps on 2,000 unprotected wood poles, subject to resource/external constraints and other execution risks	100%	N/A	0.0012%	Deploy fire-resistant wraps on 3,000 unprotected wood poles, subject to resource constraints and other execution risks	100%	N/A	0.0014%	6,000	8.2; p. 222
8.2 Grid Design & System Hardening	Quantitative	Transmission Proactive Splice Shunting (SH-20)	SH-20	Splices	Perform splice shunting of 500 splices, subject to resource/external constraints and other execution risks	100%	N/A	0.004%	Perform splice shunting based on learnings from 2026, subject to resource/external constraints and other execution risks	100%	N/A	N/A	Perform splice shunting based on learnings from 2026 and 2027, subject to resource constraints and other execution risks	100%	N/A	N/A	Sum of 500 and the number of splices based on learnings from 2026 and 2027	8.2; p. 222
8.2 Grid Design & System Hardening	Quantitative	Long Span Initiative (SH-14)	SH-14	Spans	Remediate 600 spans in SCE's HFRA, subject to resource constraints and other execution risks	100%	N/A	0.02%	Remediate 400 spans in SCE's HFRA, subject to resource constraints and other execution risks	100%	N/A	0.003%	Remediate the balance of remaining spans in SCE's HFRA, subject to resource constraints and other execution risks	100%	N/A	N/A	1,000 + balance of remaining spans	8.2; p. 222

Initiative	Quantitative or Qualitative Target	Activity (Tracking ID #)	Previous Tracking ID (if applicable)	Target Unit	2026 Target / Status [1]	% Planned in HFTD [2] for 2026	% Planned in HFRA for 2026	% Risk Reduction for 2026	2027 Target / Status [1]	% Planned in HFTD [2] for 2027	% Planned in HFRA for 2027	% Risk Reduction for 2027	2028 Target / Status [1]	% Planned in HFTD [2] for 2028	% Planned in HFRA for 2028	% Risk Reduction for 2028	Three-Year Total	Section; Page number
8.2 Grid Design & System Hardening	Qualitative	Vibration Damper Retrofit (SH-16)	SH-16	Vibration Dampers	Complete remaining scope from prior program year(s).	N/A	N/A	N/A	Pending engineering and risk analysis of needs going forward.	N/A	N/A	N/A	Pending engineering and risk analysis of needs going forward.	N/A	N/A	N/A	N/A	8.2; p. 222
8.3 Asset Inspections	Quantitative	Distribution HFRI Inspections (Ground and Aerial) (IN-1.1)	IN-1.1	Inspected Structures	Inspect 206,000 structures in HFRA This target includes HFRI inspections, compliance due structures in HFRA and emergent risks identified during the fire season (e.g., AOCs).	100%	N/A	1.78%	Inspect 206,000 structures in HFRA This target includes HFRI inspections, compliance due structures in HFRA and emergent risks identified during the fire season (e.g., AOCs).	100%	N/A	1.66%	Inspect 206,000 structures in HFRA This target includes HFRI inspections, compliance due structures in HFRA and emergent risks identified during the fire season (e.g., AOCs).	100%	N/A	1.58%	618,000	8.3; p.273
8.3 Asset Inspections	Quantitative	Transmission HFRI Inspections (Ground and Aerial) (IN-1.2)	IN-1.2	Inspected Structures	Inspect 27,700 structures in HFRA This target includes HFRI inspections, compliance due structures in HFRA and emergent risks identified during the fire season (e.g., AOC).	100%	N/A	0.01%	Inspect 27,700 structures in HFRA This target includes HFRI inspections, compliance due structures in HFRA and emergent risks identified during the fire season (e.g., AOC).	100%	N/A	0.01%	Inspect 27,700 structures in HFRA This target includes HFRI inspections, compliance due structures in HFRA and emergent risks identified during the fire season (e.g., AOC).	100%	N/A	0.01%	83,100	8.3; p.273
8.3 Asset Inspections	Quantitative	Distribution Infrared (IR) Scanning (IN-3)	IN-3	Circuit Miles Inspected	Inspect 5,300 distribution overhead circuit miles in HFRA	100%	N/A	0.00003%	Inspect 5,300 distribution overhead circuit miles in HFRA	100%	N/A	0.00004%	Inspect 5,300 distribution overhead circuit miles in HFRA	100%	N/A	0.00003%	15,900	8.3; p.273
8.3 Asset Inspections	Quantitative	Transmission Infrared and Corona Scanning (IN-4)	IN-4	Circuit Miles Inspected	Inspect 1,000 transmission overhead circuit miles in HFRA	100%	N/A	0.000003%	Inspect 1,000 transmission overhead circuit miles in HFRA	100%	N/A	0.000002%	Inspect 1,000 transmission overhead circuit miles in HFRA	100%	N/A	0.000001%	3,000	8.3; p.273
8.3 Asset Inspections	Quantitative	Generation HFRI Inspections (IN-5)	IN-5	Inspected Assets	Inspect 160 generation related assets in HFRA	100%	N/A	0.00004%	Inspect 170 generation related assets in HFRA	100%	N/A	0.00003%	Inspect 160 generation related assets in HFRA	100%	N/A	0.00003%	490	8.3; p.273
8.4 Equipment Maintenance & Repair	Qualitative	Review Transmission and Distribution HFRI Inspection Survey (IN-10)	N/A	N/A	Review transmission and distribution HFRI inspections survey and revise as needed	N/A	N/A	N/A	Review transmission and distribution HFRI inspections survey and revise as needed	N/A	N/A	N/A	Review transmission and distribution HFRI inspections survey and revise as needed	N/A	N/A	N/A	N/A	8.4; p.290
8.6 Work Orders	Qualitative	Asset Work Order Reduction (IN-11)	N/A	Inspection Finding Remediations	Close 70% of P2 notifications in HFRA with ignition-risk potential that are past due (as of Dec 31, 2025) in the "Inactive equipment/FLOC" and "Other" categories.	100%	N/A	N/A	Close 70% of P2 notifications in HFRA with ignition-risk potential that are past due (as of December 31, 2026) in the "Inactive equipment/FLOC" and "Other" categories	100%	N/A	N/A	Close 70% of P2 notifications in HFRA with ignition-risk potential that are past due (as of December 31, 2027) in the "Inactive equipment/FLOC" and "Other" categories	100%	N/A	N/A	N/A	8.6; p.310

Initiative	Quantitative or Qualitative Target	Activity (Tracking ID #)	Previous Tracking ID (if applicable)	Target Unit	2026 Target / Status [1]	% Planned in HFTD [2] for 2026	% Planned in HFRA for 2026	% Risk Reduction for 2026	2027 Target / Status [1]	% Planned in HFTD [2] for 2027	% Planned in HFRA for 2027	% Risk Reduction for 2027	2028 Target / Status [1]	% Planned in HFTD [2] for 2028	% Planned in HFRA for 2028	% Risk Reduction for 2028	Three-Year Total	Section; Page number
8.7 Grid Operations & Procedures	Quantitative	REFCL (Ground Fault Neutralizer) (SH-17)	SH-17	Completed Construction at Substation	Complete construction of Ground Fault Neutralizers at one substation, subject to resource constraints and other execution risks	100%	N/A	0.48%	Complete construction of Ground Fault Neutralizers at two substations, subject to resource constraints and other execution risks	100%	N/A	0.08%	Complete construction of Ground Fault Neutralizers at two substations, subject to resource/external constraints and other execution risks	100%	N/A	0.88%	5	8.7; p.316
8.7 Grid Operations & Procedures	Quantitative	REFCL (Grounding Conversion) (SH-18)	SH-18	Completed Construction at Location	Complete construction for grounding conversions at two locations, subject to resource constraints and other execution risks	100%	N/A	1.27%	Complete construction for grounding conversions at three locations, subject to resource constraints and other execution risks	100%	N/A	0.14%	Complete construction for grounding conversions at three locations, subject to resource/external constraints and other execution risks	100%	N/A	0.16%	8	8.7; p.316
8.7 Grid Operations & Procedures	Quantitative	Remote Controlled Automatic Reclosers (SH-5)	SH-5	RAR/RCS devices	Install 5 RAR/RCS sectionalizing devices subject to needs based on prior year and to resource/external constraints and other execution risks	100%	N/A	0.00004%	Install 5 RAR/RCS sectionalizing devices subject to needs based on prior year and to resource/external constraints and other execution risks.	100%	N/A	0.00028%	Install 5 RAR/RCS sectionalizing devices, subject to needs based on prior year and to resource/external constraints and other execution risks	100%	N/A	0.00023%	15	8.7; p.316
8.8 Workforce Planning	Qualitative	Workforce Planning (IN-12)	IN-12	N/A	Review asset inspections training curriculum	N/A	N/A	N/A	Implement revised asset inspections training curriculum, based on 2026 results	N/A	N/A	N/A	As needed, incorporate feedback and updates to curriculum	N/A	N/A	N/A	N/A	8.8; p.328

[1] The completion date for all qualitative targets is December 31, unless otherwise specified.
[2] A small number of incidental miles (in the case of WCCP) or coverage (in the case of REFCL) may occur outside of HFTD due to projects that traverse HFTD and non-HFTD areas.

8.2 Grid Design and System Hardening

In this section the electrical corporation must discuss how it is designing its system to reduce overall utility risk and what it is doing to strengthen its distribution, transmission, and substation infrastructure to reduce the risk of utility-related ignitions resulting in catastrophic wildfires.

The electrical corporation is required to discuss grid design and system hardening for each of the following individual 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*
12. *Other technologies and systems not listed above*
13. *Status updates on additional technologies being piloted*

In Sections 8.2.1 – 8.2.13, the electrical corporation must provide a narrative that supports the qualitative targets identified in Section 8.1.1 including the following information for each grid design and system hardening initiative activity:

- ***Tracking ID***
- ***Overview of the activity****: A brief description of the activity including reference to related objectives and targets. Additionally, the overview must identify whether the activity is a program, project, pilot, or study.*
- ***Impact of the activity on wildfire risk.***

- *The expected percent wildfire risk reduction/effectiveness, with level of granularity included, (e.g., service territory, HFTD, circuit segment, etc.) for the activity, including an explanation of the calculation, a list of assumptions, and justifications for each assumption. A risk reduction/effectiveness of 100% means no risk remains after the electrical corporation completes the activity.*
- *A trend analysis showing how implementation of the activity has reduced risk over time for each relevant risk and/or risk driver (e.g. vegetation contact for covered conductor installation).*
- *A discussion of how the activity impacts the likelihood and consequence of ignitions.*

- ***Impact of the activity on outage program risk***
  - *The expected percent reliability risk reduction/effectiveness for the activity, including an explanation of the calculation, a list of assumptions, and justifications for each assumption. A risk reduction/effectiveness of 100% means no risk remains after the electrical corporation completes the activity.*
  - *A discussion of how the electrical corporation considers and evaluates the hardened status of upstream circuits/segments/spans to determine the impact of the activity on reliability risk.*
  - *A discussion of how the activity impacts the likelihood and consequence of outage program events, including whether an area would still be subject to PSPS events after the electrical corporation completes the activity.*
  - *A discussion of how the activity impacts overall reliability, including how trends are being observed. This must include evaluation of number of outages occurring, the duration for those outages, and the number of customers affected during those outages.*

- ***Updates to the activity:***
  - *A list of the changes the electrical corporation made to the activity since its last WMP submission.*
  - *Justification for each of the changes, including references to lessons learned.*
  - *A list of planned future improvements and/or updates to the activity, including a timeline for implementation.*
  - *As applicable, a discussion of the status of any undergrounding work plans and progress, as required by Public Utilities Code section 8388.5(f)(2).*

- *As applicable, a discussion of any evaluations related to scoping grid hardening projects to account for future grid needs (e.g., load capacity, peak demand, system flexibility).*

- ***Compatible initiatives:***
  - *A list of other activities the electrical corporation uses in combination with the activity to increase risk reduction effectiveness, including the section number and a link to the corresponding WMP section. This must be consistent with the evaluations performed in Section 6.1.3.1 and must include all activities that can be feasibly deployed in combination.*

If the electrical corporation does not undertake one or more of the 13 initiative activities listed above, the electrical corporation must provide a brief narrative for each activity, explaining why it does not undertake that activity.

Regarding the impact risk for activities below, SCE notes that it is challenging to isolate the effect of an individual mitigation on historical trends for wildfire risk and outage risk for two reasons:

Multiple mitigations have been applied in recent years in a portfolio approach that is intended to collectively reduce wildfire and/or outage program risk. For example, the combination of asset inspections, vegetation management activities, and hardening programs collectively contribute to reduced instances of both foreign object contact with overhead lines and instances of individual components failing. Annual variations in weather and vegetation conditions (e.g., amount of growth based on rainfall or the presence of dry vegetation) significantly influence wildfire risk and the occurrence of risk drivers, further complicating the issue of isolating the effect of an individual mitigation from environmental effects that vary each year.

With the exception of covered conductor, which provides a large data set of thousands of covered and uncovered overhead circuit miles for multiple years, the information on trend analysis that SCE provides below focuses on how deployment of hardening mitigations is *associated with* observed trends in faults, ignitions, and wire downs. The reported outcomes should not be construed as the causal effect of such mitigations.

8.2.1 Covered Conductor Installation

8.2.1.1 Covered Conductor

Tracking ID: SH-1

Overview of Activity: The Wildfire Covered Conductor Program (WCCP) is a program to replace existing bare wire with covered conductor (CC) along with other associated components such as fire-resistant poles, composite crossarms, FR3 transformers,[110] wildlife covers, surge arresters, polymer insulators and vibration dampers, and is scoped based on the risk assessment and mitigation selection processes described in Chapter 6.

Covered conductor refers to a conductor with an internal semiconducting layer and external insulating UV-resistant layers to protect against the arcing, faults, or energy release that can come from incidental contact.

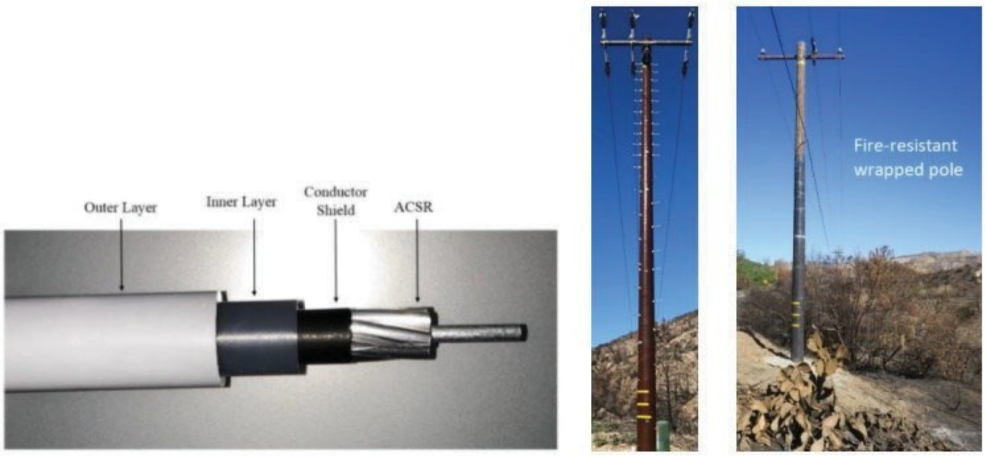
SCE's engineering standard is to install covered conductor if bare wire needs to be replaced. Examples of this include during post-fire restoration work (outside of the WCCP) and other non-WCCP programmatic work such as the Overhead Conductor Program (OCP), where bare wires are replaced. SCE tracks and reports the installation of covered conductor under both WCCP and non-WCCP.

SCE installs composite poles or fire-resistant wrapped wood poles (together known as Fire-Resistant Poles or FRPs) during the implementation of WCCP when pole loading requirements require a replacement of a pole. See section 8.2.3.1 for discussion on SCE's plans to expand fire-resistant pole deployment.

FRPs provide the benefits of withstanding a fire, maintaining system resiliency, and shortening the service restoration time. Figure SCE 8-01 shows the physical layers of covered conductor, as well as illustrations of a fire-resistant composite pole and a fire-resistant wrapped wood pole.

110 A FR3 transformer contains plant-based oil instead of petroleum-based oil and can withstand higher temperatures before igniting, reducing the chances of the transformer fluid adding fuel to a fire.

Figure SCE 8-01: Cross Section of Covered Conductor (left) and Composite and Fire-Resistant Wrapped Poles (right)



SCE's covered conductor activity targets are provided in Table 8-1. If factors outside of SCE's control facilitate execution of additional units, SCE will strive to install up to 695 circuit miles of covered conductor over the three-year period. This level of execution depends on exogenous factors like the issuance of permits and environmental clearances.

Impact of activity on wildfire risk:

The expected percent wildfire risk reduction/effectiveness, with level of granularity included, for the activity, including an explanation of the calculation, a list of assumptions, and justifications for each assumption.

Please see Table SCE 6-01 and Table 6-3 for mitigation effectiveness and risk reduction values. Table SCE 6-02 provides the basis for SCE's mitigation effectiveness assumptions. The calculation are explained in the narrative immediately following Table 6-3.

A trend analysis showing how implementation of the activity has reduced risk over time for each relevant risk and/or risk driver (e.g. vegetation contact for covered conductor installation).

Areas with covered conductor averaged 82% fewer Animal Contact, 94% fewer Balloon, 80% fewer Other Contact, 50% fewer Vegetation Contact, and 50% fewer Vehicle Contact faults per mile in 2024. Furthermore, there were 33% fewer Equipment Facility Failure and 43% fewer other faults per mile in 2024.

A discussion of how the activity impacts the likelihood and consequence of ignitions.

Please see the tables referenced above. SCE also notes that this mitigation does not reduce the consequence of ignitions, as its purpose is to reduce the ignition from occurring in the first place.

Zero ignitions have occurred from the drivers mitigated by covered conductor at locations where covered conductor is deployed.[111]

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111 As of year-end 2024.

Impact of activity on outage program risk:

The expected percent reliability risk reduction/effectiveness for the activity, including an explanation of the calculation, a list of assumptions, and justifications for each assumption. A risk reduction/effectiveness of 100% means no risk remains after the electrical corporation completes the activity.

Please see Table SCE 6-01 and Table 6-3 for mitigation effectiveness and risk reduction values. Table SCE 6-02 Provides the basis for SCE's mitigation effectiveness assumptions The calculations below correspond to the values in Table 6-3.

A discussion of how the electrical corporation considers and evaluates the hardened status of upstream circuits/segments/spans to determine the impact of the activity on reliability risk.

Because of directional power flow from a source substation to the end of a line, even a fully covered isolatable circuit segment can still be subject to faults or PSPS de-energizations from upstream circuit segments. For this reason, SCE considers the grid topology of upstream circuitry and applies mitigations, if practical.

A discussion of how the activity impacts the likelihood and consequence of outage program events, including whether an area would still be subject to PSPS events after the electrical corporation completes the activity.

When a circuit (or fully isolatable circuit segment) is entirely covered conductor, the de-energization threshold is increased from the bare conductor threshold of 31/46 mph (sustained wind/gusts) to the covered conductor threshold of 40/58 mph. This means that covered conductor reduces the likelihood of a PSPS de-energization and the duration of a PSPS de-energization should it be necessary.

A discussion of how the activity impacts overall reliability, including how trends are being observed. This must include evaluation of number of outages occurring, the duration for those outages, and the number of customers affected during those outages.

Covered conductor improves reliability. On circuits where the overhead primary is all covered conductor, as shown in Figure 2 in part 1.1.4 of the response to ACI SCE-25U-03 in Appendix D: Areas for Continued Improvement, SCE has observed an approximately 60% reduction of faults per mile compared to bare wire. While not all faults result in an outage, the decrease in faults on covered circuits is a meaningful proxy for the improved reliability of covered conductor relative to bare overhead wire.

Updates to the activity:

A list of the changes the electrical corporation made to the activity since its last WMP submission.

SCE has not changed this program since its last WMP. Based on miles to date and anticipated remaining scope, SCE plans to be substantially finished with proactive covered conductor installation in its HFRA by the end of this WMP cycle.[112] However, certain factors could extend WCCP past 2028, which include, but are not limited to, modeled risk, HFTD boundaries, GRC decision, change in Targeted Undergrounding (TUG) scope, and change in strategy. Approximately 1,000 distribution circuit miles in HFRA will not have CC or TUG by the end of 2028, if SCE achieves its strive targets. However, as CC is now the overhead standard for SCE, those miles would eventually be hardened. If SCE does not reach its strive miles by the end of 2028, SCE will continue with its CC program in its 2029-2031 WMP.

Justification for each of the changes, including references to lessons learned.

N/A.

A list of planned future improvements and/or updates to the activity, including a timeline for implementation.

SCE is developing an updated standard for covered conductor that will use a newer covered conductor material that provides incremental improvements in reduced thickness and weight, increased moisture blocking, and increased resistance to ice buildup. Based on the timing to finalize the newer design standards and material ordering, SCE anticipates the newer covered conductor will be used for projects in approximately 2027. Also, SCE is re- evaluating its risk assessments and may determine that to mitigate wildfire and WUI conflagration risk, SCE may install covered conductor outside of HFRA, separate and apart from its HFRA covered conductor projects, in the 2026-2028 timeframe. In addition, if undergrounding is not feasible or otherwise limited by one of the factors listed above, SCE would consider alternatives including CC, REFCL, remote grid, etc.

As applicable, a discussion of the status of any undergrounding work plans and progress, as required by Public Utilities Code section 8388.5(f)(2).

N/A.

As applicable, a discussion of any evaluations related to scoping grid hardening projects to account for future grid needs (e.g., load capacity, peak demand, system flexibility).

N/A.

Compatible Initiatives:

- IN-1.1: Distribution HFRI Inspections (Section 8.3.1)
- IN-3: Distribution IR (Section 8.3.3)
- SA-11: Early Fault Detection (EFD) (Chapter 10.3.1)
- SA-14: Distribution Open Phase Detection (DOPD) (Chapter10.3.1)
- SH-1: Covered Conductor (Section 8.2.1.1)
- SH-16: Vibration Damper Retrofit (Section 8.2.1.2)
- SH-17: REFCL (Ground Fault Neutralizer) (Section 8.2.6.1)
- SH-18: REFCL (Grounding Conversion) (Section 8.2.6.2)
- SH-19: FR Wrap Expanded Deployment (Section 8.2.3.1)
- SH-5: Remote Controlled Automatic Reclosers (Section 8.2.8.1)
- VM-2.1: Additional Structure Brushing (Chapter 9.4.1.2)
- VM-2.2: Compliance Structure Brushing (Chapter 9.4.1.1)
- VM-7: Distribution VM Clearances (Chapter 9.2.1)

112 Proactive covered conductor installation may continue beyond 2028 based on changing HFRA boundaries or shifts in strategy. If the Petition for Modification to the HFTD boundaries is approved, newly in-scope areas would be evaluated for proactive CC deployment. SCE is evaluating risk from traveling faults (i.e., faults that occur in a particular location, but travel along connected wires and release fault energy upstream or downstream), which may result in a programmatic expansion of WCCP.

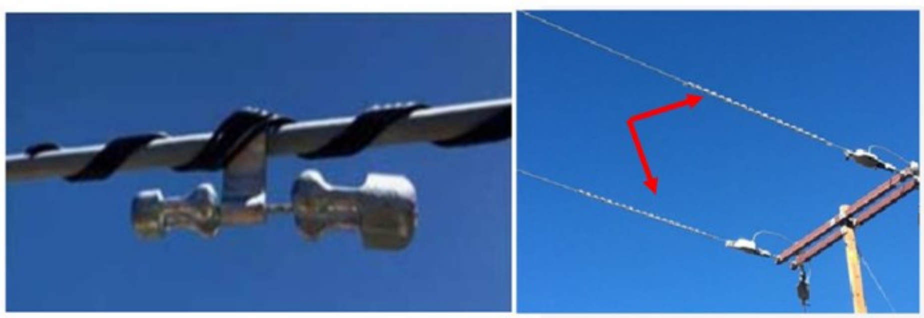
8.2.1.2 Vibration Damper Retrofit

Tracking ID: SH-16

Overview of activity: SCE's vibration damper retrofit program aims to stop wind-driven vibration (known as Aeolian vibration) that may lead to conductor abrasion or fatigue over time. This is an issue for both bare and covered conductor. However, covered conductor may be more susceptible to vibration because of the covering's smoothness (perfect cylinder) and the reduction of strand movement due to the covering.

While it does not pose an immediate risk, vibration can reduce the covered conductor's useful life from 45 years to an average of 20 years if not addressed, particularly in high and medium vibration susceptibility areas. Figure SCE 8-02 shows two types of vibration dampers.

Figure SCE 8-02: Types of Vibration Dampers: Stockbridge Damper (left) and Spiral Damper (right)



The vibration damper retrofit program targets covered conductor installations constructed prior to Q4 2020, when SCE's vibration damper standard was published. SCE examines potential areas for damper retrofits and prioritizes lines based on defined terrain type categories and persistence of wind. SCE uses a risk-informed analysis to determine CC installations with high, medium, and low susceptibility to Aeolian vibrations. For new covered conductor installations, vibration dampers are required per SCE's covered conductor construction standard.

SCE's vibration damper activity targets are provided in Table 8- 1.

Impact of activity on wildfire risk:

The expected percent wildfire risk reduction/effectiveness, with level of granularity included, for the activity, including an explanation of the calculation, a list of assumptions, and justifications for each assumption.

Installing vibration dampers maintains the expected useful life of the covered conductor, and thus the ability of covered conductor to minimize certain equipment failure ignition drivers, such as damage or failure of the conductor, connector, and/or splice. As such, please see the section immediately prior on covered conductor's effectiveness.

A trend analysis showing how implementation of the activity has reduced risk over time for each relevant risk and/or risk driver (e.g. vegetation contact for covered conductor installation).

Please see above.

A discussion of how the activity impacts the likelihood and consequence of ignitions.

Please see above.

Impact of activity on outage program risk:

The expected percent reliability risk reduction/effectiveness for the activity, including an explanation of the calculation, a list of assumptions, and justifications for each assumption. A risk reduction/effectiveness of 100% means no risk remains after the electrical corporation completes the activity.

Please see above.

A discussion of how the electrical corporation considers and evaluates the hardened status of upstream circuits/segments/spans to determine the impact of the activity on reliability risk.

Please see above.

A discussion of how the activity impacts the likelihood and consequence of outage program events, including whether an area would still be subject to PSPS events after the electrical corporation completes the activity.

Please see above.

A discussion of how the activity impacts overall reliability, including how trends are being observed. This must include evaluation of number of outages occurring, the duration for those outages, and the number of customers affected during those outages.

Please see above.

Updates to the activity:

A list of the changes the electrical corporation made to the activity since its last WMP submission.

SCE has not changed this program since its last WMP.

Justification for each of the changes, including references to lessons learned.

N/A.

A list of planned future improvements and/or updates to the activity, including a timeline for implementation.

SCE anticipates completing the remaining vibration damper retrofit program scope in 2026; activity beyond 2026 is pending engineering and risk analysis.

As applicable, a discussion of the status of any undergrounding work plans and progress, as required by Public Utilities Code section 8388.5(f)(2).

N/A.

As applicable, a discussion of any evaluations related to scoping grid hardening projects to account for future grid needs (e.g., load capacity, peak demand, system flexibility).

N/A.

Compatible initiatives: This activity can be combined with Covered Conductor (SH-1) (See Section 8.2.11).

8.2.2 Undergrounding of Electric Lines and/or Equipment

8.2.2.1 Targeted Undergrounding in HFRA

Tracking ID: SH-2

Overview of activity: Targeted Undergrounding (TUG) is a program to underground existing overhead power lines to significantly reduce wildfire and PSPS risk by reducing the possibility for objects to contact energized conductor as well as greatly limiting the ignition-causing potential from equipment failures. In addition to those drivers, fault conditions can weaken and sometimes cause electrical stresses on hardware and insulators, which could lead to energized wire-down events or electrical arcing. Replacing overhead lines with underground wire significantly reduces those risks.

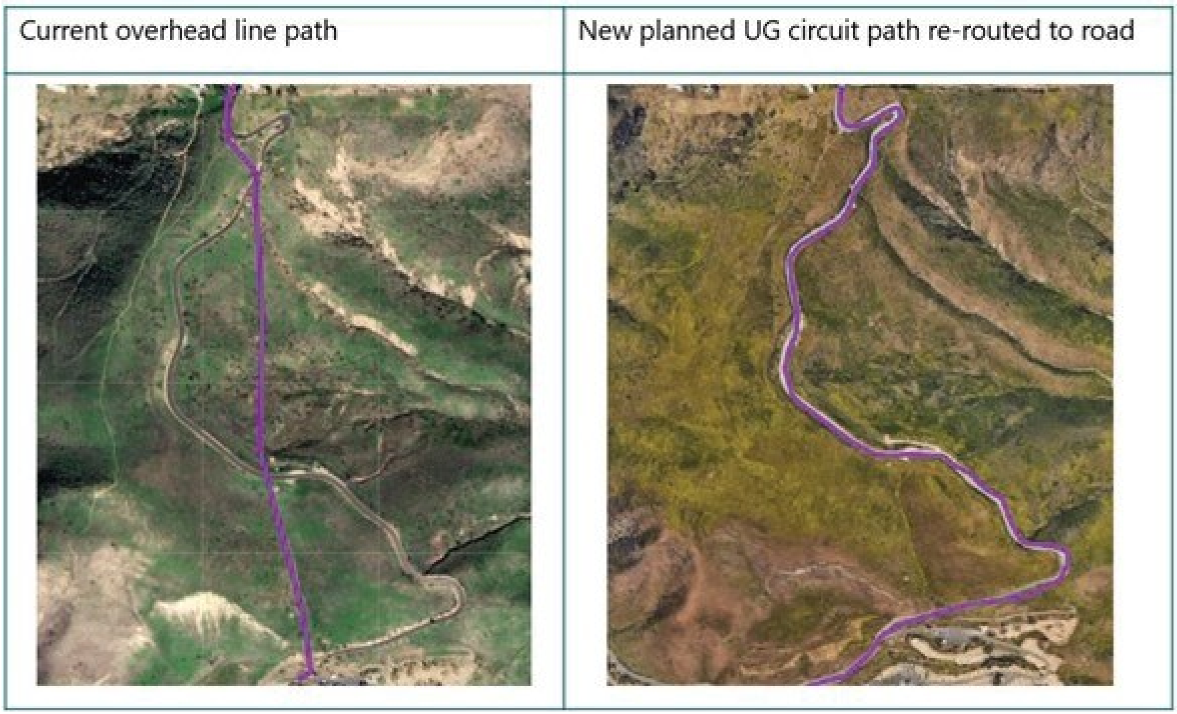
Undergrounding also has the added benefit of reducing the need for PSPS during extreme wind events. While the deployment of covered conductor may significantly increase the windspeed threshold for de-energization during a risk event, it does not completely prevent those de-energizations during extreme wind events like undergrounding can. Because of directional power flow from a source substation to the end of a line, even a fully undergrounded isolatable circuit segment can still be subject to faults or PSPS de-energizations from upstream circuit segments. Accordingly, as described in Section 6, undergrounding is the preferred method to nearly eliminate risk in Severe Risk Areas. However, there are some locations that are not feasible to underground due to factors such as rocky terrain, etc. In those cases, SCE would instead consider other mitigation measures including covered conductor combined with other measures.

Generally, when converting existing overhead lines to underground facilities, a line route needs to be determined. Often in urbanized areas, this route can be the same as the existing overhead line assuming pre-existing underground utilities (e.g., natural gas, water, sewer, etc.) do not preclude the addition of a new duct and structure system. Routes may also need to be altered to avoid obstructions. For example, this may involve moving a rear property pole line to curbside to avoid swimming pools, block walls, etc.

In coastal, mountainous, or more rural communities, topography can present additional challenges to those already mentioned above. Lines may need to be moved to the road to avoid steep terrain, heavy vegetation, water crossings, erosion concerns, and to generally avoid environmental considerations associated with heavy equipment access to construct and/or maintain lines. Because of these topographical challenges with some existing overhead lines, undergrounding along the same route may be impractical. Therefore, overhead lines may need to be brought out to the public right-of-way for undergrounding, increasing the length of the undergrounding needed and increasing the cost and construction timeline.

Figure SCE 8-03 shows an example of a necessary re-route. The picture on the left shows the current overhead line path, crossing a steep, hilly terrain. The lines may need to be moved to the road to avoid environmental considerations associated with heavy equipment access to construct and/or maintain lines, as shown in the picture on the right. Re-routing requires an additional length of conductor, labor, and materials.

Figure SCE 8-03: Re-Route Example in Malibu Area



SCE’s targeted undergrounding activity targets are provided in Table 8-1. If factors outside of SCE’s control facilitate execution of additional units, SCE will strive to convert up to 440 circuit miles of overhead to underground in SCE’s HFRA over the three-year period. This level of execution depends on exogenous factors like the issuance of permits and environmental clearances.

Impact of activity on wildfire risk:

The expected percent wildfire risk reduction/effectiveness, with level of granularity included, for the activity, including an explanation of the calculation, a list of assumptions, and justifications for each assumption.

Please see Table SCE 6-01 and Table 6-3: SCE Risk Impact of Activities for mitigation effectiveness and risk reduction values. Table SCE 6-02 provides the basis for SCE's mitigation effectiveness assumptions. The calculations are explained in the narrative immediately following Table 6-3: SCE Risk Impact of Activities.

A trend analysis showing how implementation of the activity has reduced risk over time for each relevant risk and/or risk driver (e.g. vegetation contact for covered conductor installation).

Areas with targeted undergrounding that removed existing overhead facilities for the express purpose of wildfire mitigation have had no ignitions in HFRA.

A discussion of how the activity impacts the likelihood and consequence of ignitions.

Please see the tables referenced above. SCE also notes that this mitigation does not reduce the consequence of ignitions, as its purpose is to reduce the ignition from occurring in the first place.

Impact of activity on outage program risk:

The expected percent reliability risk reduction/effectiveness for the activity, including an explanation of the calculation, a list of assumptions, and justifications for each assumption. A risk reduction/effectiveness of 100% means no risk remains after the electrical corporation completes the activity.

Please see Table SCE 6-01 and Table 6-3: SCE Risk Impact of Activities for mitigation effectiveness and risk reduction values. Table SCE 6-02 provides the basis for SCE's mitigation effectiveness assumptions. The calculations are explained in the narrative immediately following Table 6-3: SCE Risk Impact of Activities.

Undergrounding substantially reduces the risk of PSPS on circuits and isolatable segments that are fully undergrounded. However, as noted above, even a fully undergrounded isolatable circuit segment can be subject to faults or PSPS de-energizations from upstream circuit segments.

A discussion of how the electrical corporation considers and evaluates the hardened status of upstream circuits/segments/spans to determine the impact of the activity on reliability risk.

Isolatable circuit segments that are connected to upstream overhead circuits can still experience PSPS outage if there is no way to reroute them to get power from another non-PSPS impacted circuit.

A discussion of how the activity impacts the likelihood and consequence of outage program events, including whether an area would still be subject to PSPS events after the electrical corporation completes the activity.

Please see the response immediately prior regarding upstream overhead circuits.

A discussion of how the activity impacts overall reliability, including how trends are being observed. This must include evaluation of number of outages occurring, the duration for those outages, and the number of customers affected during those outages.

Undergrounding nearly eliminates the potential for many types of faults that can lead to outages. Areas with targeted undergrounding that removed existing overhead facilities for the express purpose of wildfire mitigation have not had faults or outages in HFRA.

Updates to the activity:

A list of the changes the electrical corporation made to the activity since its last WMP submission.

While SCE has not materially changed its scoping or prioritization approach, SCE is working on improvements related to the planning and implementation of SH-2. SCE has modified its land acquisition process, internal process improvements, increased agency engagement, and customer engagement. Please also see SCE's response to ACI SCE-25U-04 for more information on considerations made for target setting.

Justification for each of the changes, including references to lessons learned.

SCE did not achieve its targets for SH-2 in both 2023 and 2024, which led SCE to consider opportunities for improvement. In addition to reviewing its own practices, SCE conducted benchmarking with Pacific Gas and Electric Company (PG&E) and San Diego Gas & Electric Company (SDG&E) to understand and learn best practices.

A list of planned future improvements and/or updates to the activity, including a timeline for implementation.

All of the changes are in the process of implementation:

- Land acquisition process: Increasing activities performed in parallel, including obtaining property owner permissions and easements.
- Internal process improvements: Enhancing internal reporting to more rapidly identify and address constraints.
- Increased agency engagement: Meeting with federal and state agencies to review project portfolio, discuss permitting strategies, and obtain feedback on project design.
- Customer engagement: Increase customer communications, in particular before starting work, and increase partnerships with local community groups and cities.

As applicable, a discussion of the status of any undergrounding work plans and progress, as required by Public Utilities Code section 8388.5(f)(2).

N/A. At this time, SCE does not intend to submit an Expedited Undergrounding Plan.

As applicable, a discussion of any evaluations related to scoping grid hardening projects to account for future grid needs (e.g., load capacity, peak demand, system flexibility).

N/A.

Compatible initiatives:

- SH-17: REFCL (Ground Fault Neutralizer) (Section 8.2.6.1)
- SH-18: REFCL (Grounding Conversion) (Section 8.2.6.2)

8.2.2.2 Ground-Level Distribution System (GLDS) & At Grade Duct Bank (AGDB)

Tracking ID: 8.2.2.2

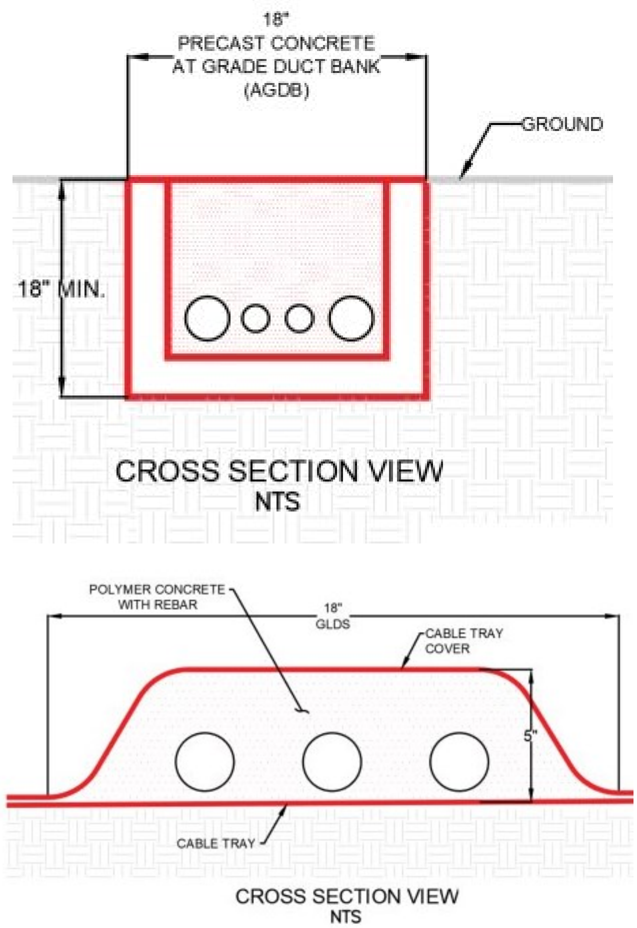
Overview of the activity: Ground level distribution system (GLDS) and At Grade Duct Bank (AGDB) are new pilot technologies that SCE is exploring as a potential alternative to traditional undergrounding.

- GLDS would place cables in conduit, encased in a composite fill, inside a cable tray assembly on the ground, which can be installed at ground level or shallow trenched across roadways or other potential thoroughfares, thereby avoiding much of the expense and time associated with excavating and trenching for traditional undergrounding depth.
- AGDB involves installing conduits in a precast cable trench filled with concrete, offering benefits such as easier installation at ground level, support in areas prone to ground movement, and customization for varying cable sizes. **Figure SCE 8-04a** below shows a PG&E pilot GLDS installation in San Mateo County.

Figure SCE 8-04a: Cover Installed Over Cable Tray System from PG&E's GLDS Pilot in Woodside

AGBD is conceptually similar to GLDS but differs by installing a shallow cable trench that sits at ground level, as show in Figure SCE 8-04b.

Figure SCE 8-04b: Cross-Section View of AGDB (above) and GLDS (below)



Other potential benefits include cost savings from less soil disposal and restoration, the ability to install in more rugged/rough terrain, and minimal construction impacts to the surrounding area. SCE has benchmarked with PG&E to learn about their GLDS pilot, which appears to preliminarily bear out these benefits. Lines and trays installed in this fashion are far less prone to vegetation-related risks and offer protection from pedestrians and vehicles.

During the pilot, SCE will seek to determine constructability of this technology so that SCE standards can potentially be developed for future installations. SCE will also determine if costs and operational reliability in practice are as advertised.

Impact of activity on wildfire risk:

The expected percent wildfire risk reduction/effectiveness, with level of granularity included, for the activity, including an explanation of the calculation, a list of assumptions, and justifications for each assumption.

Because this is a new pilot, SCE has not yet calculated a wildfire risk mitigation effectiveness. The premise for the pilot is that GLDS and AGDB would provide a level of risk reduction similar to undergrounding and would substantially reduce the risk of ignitions and outages associated with drivers such as wire contact with objects (e.g., vegetation, metallic balloons, debris, etc.), equipment failure, and wire-to-wire faults.

A trend analysis showing how implementation of the activity has reduced risk over time for each relevant risk and/or risk driver (e.g. vegetation contact for covered conductor installation)

This is a new pilot at SCE; trending analysis is not available.

A discussion of how the activity impacts the likelihood and consequence of ignitions.

Please see above.

Impact of activity on outage program risk:

The expected percent reliability risk reduction/effectiveness for the activity, including an explanation of the calculation, a list of assumptions, and justifications for each assumption. A risk reduction/effectiveness of 100% means no risk remains after the electrical corporation completes the activity.

SCE anticipates that GLDS/AGDB will have similar mitigation effectiveness as traditional undergrounding, substantially reducing the risk of PSPS and other outages on circuits and isolatable segments that are fully treated.[113]

A discussion of how the electrical corporation considers and evaluates the hardened status of upstream circuits/segments/spans to determine the impact of the activity on reliability risk.

Isolatable circuit segments that are connected to upstream overhead circuits can still experience PSPS outages if there is no way to reroute them to get power from another non-PSPS impacted circuit. For this reason, SCE considers the grid topology of upstream circuitry and applies mitigations, if practical.

A discussion of how the activity impacts the likelihood and consequence of outage program events, including whether an area would still be subject to PSPS events after the electrical corporation completes the activity.

If the lower overall rate of faults on undergrounded circuits is similarly proven out on a GLDS/AGDB installation, the likelihood of outages would also be reduced.

A discussion of how the activity impacts overall reliability, including how trends are being observed. This must include evaluation of number of outages occurring, the duration for those outages, and the number of customers affected during those outages.

113 Note that isolatable segments that are connected to upstream overhead circuits can still experience PSPS outages if there is no way to reroute them to get power from another non-PSPS impacted circuit.

Information relating to reliability trends is not available for this new activity. As noted above, undergrounding improves reliability by mostly eliminating many potential faults that can occur on overhead lines.

Updates to the activity:

A list of the changes the electrical corporation made to the activity since its last WMP submission.

N/A. This is a new activity.

Justification for each of the changes, including references to lessons learned.

N/A.

A list of planned future improvements and/or updates to the activity, including a timeline for implementation.

N/A.

As applicable, a discussion of the status of any undergrounding work plans and progress, as required by Public Utilities Code section 8388.5(f)(2).

N/A.

As applicable, a discussion of any evaluations related to scoping grid hardening projects to account for future grid needs (e.g., load capacity, peak demand, system flexibility).

N/A.

Compatible initiatives: This is a new pilot for SCE and compatibility is to be determined. As noted above, SCE expects it would be aligned with undergrounding in terms of compatible mitigations.

8.2.2.3 Targeted Undergrounding in January 2025 Burn Scar

Tracking ID: 8.2.2.3

Overview of activity: On February 27, 2025, Governor Newsom sent a letter in response to the Los Angeles wildfires in January 2025 in which he asked SCE to share its plan for rebuilding infrastructure in the burn scar areas. The letter stated that where infrastructure had to be completely rebuilt, SCE has the opportunity to build back a more modern, reliable and resilient electric distribution system that can meet the community's immediate and future needs. The letter also stated that it is critical this plan incorporates undergrounding to the extent feasible and should consider how this work can be done cost-effectively and quickly.

SCE shared its rebuild plan in a letter (https://www.sce.com/govletter) dated April 11, 2025. In that letter, SCE pledged to provide an update to the rebuild plan in its WMP. The rebuild plan includes, among other things, installing underground distribution lines within the burn scar areas. SCE initially intends on moving forward on an estimated 130 miles in HFRA and 23 miles in non-HFRA. SCE is also evaluating 19 additional miles in non-HFRA.

SCE considered a variety of factors in developing the scope, including wildfire and PSPS risks, operational considerations, and rebuilding in what is akin to a new development. SCE has preliminarily sequenced undergrounding scope in the following tranches. However, SCE may update its plans, as certain operational conditions may favor a different order (e.g. customer rebuild timelines, opportunities to partner with agencies to reduce costs, etc.):

First tranche: Areas in Malibu that are in HFRA and currently do not have electrical service. SCE had scoped the majority of these miles as TUG pursuant to its IWMS prior to the January 2025 fires. This tranche also includes a project in Altadena that was scoped as TUG and already in-flight prior to the January 2025 fires but was extended after the fires to provide service to customers currently on generators.

Second tranche: Areas in 1) Altadena where there are currently no electrical facilities and potentially where customers will rebuild. This may include undergrounding facilities immediately adjacent to these locations for more efficient construction and to avoid a patchwork of overhead and underground facilities in areas, and 2) Malibu line segments that SCE previously scoped for TUG that currently have service or that will allow for two circuits to be removed from distribution-driven PSPS.

Third tranche: Overhead distribution facilities in Altadena that are in HFRA and currently bare conductor.

Fourth tranche: Overhead distribution facilities in Altadena that are in HFRA and currently covered conductor.

Fifth tranche: Overhead distribution facilities in Altadena that are in non-HFRA.

In 2025, as described in section 5.7, SCE will also re-evaluate and enhance its risk modeling to incorporate risks such as urban conflagration. The results of this effort may impact the scope and prioritization of SCE's rebuilding efforts in the January 2025 fire scar area. SCE will provide the impacts of this risk analysis in its 2027 WMP Update.

Impact of activity on wildfire risk:

The expected percent wildfire risk reduction/effectiveness, with level of granularity included, for the activity, including an explanation of the calculation, a list of assumptions, and justifications for each assumption.

The mitigation effectiveness of TUG is discussed in section 8.2.2.1.

A trend analysis showing how implementation of the activity has reduced risk over time for each relevant risk and/or risk driver (e.g. vegetation contact for covered conductor installation)

A trend analysis of TUG is discussed in section 8.2.2.1.

A discussion of how the activity impacts the likelihood and consequence of ignitions.

See discussion in section 8.2.2.1.

Impact of activity on outage program risk:

The expected percent reliability risk reduction/effectiveness for the activity, including an explanation of the calculation, a list of assumptions, and justifications for each assumption. A risk reduction/effectiveness of 100% means no risk remains after the electrical corporation completes the activity.

The mitigation effectiveness of TUG is discussed in section 8.2.2.1.

A discussion of how the electrical corporation considers and evaluates the hardened status of upstream circuits/segments/spans to determine the impact of the activity on reliability risk.

See discussion in section 8.2.2.1.

A discussion of how the activity impacts the likelihood and consequence of outage program events, including whether an area would still be subject to PSPS events after the electrical corporation completes the activity.

See discussion in section 8.2.2.1.

A discussion of how the activity impacts overall reliability, including how trends are being observed. This must include evaluation of number of outages occurring, the duration for those outages, and the number of customers affected during those outages.

See discussion in section 8.2.2.1.

Updates to the activity:

A list of the changes the electrical corporation made to the activity since its last WMP submission.

N/A. This is a new activity.

Justification for each of the changes, including references to lessons learned.

N/A.

A list of planned future improvements and/or updates to the activity, including a timeline for implementation.

N/A.

As applicable, a discussion of the status of any undergrounding work plans and progress, as required by Public Utilities Code section 8388.5(f)(2).

N/A.

As applicable, a discussion of any evaluations related to scoping grid hardening projects to account for future grid needs (e.g., load capacity, peak demand, system flexibility).

N/A.

8.2.3 Distribution Pole Replacements and Reinforcements

With the exception of Fire Resistant Wrap Expanded Deployment or WCCP, SCE generally does not replace or reinforce poles that do not pose safety issues. Instead, SCE has various inspection programs that will identify poles for replacement if they are deteriorated or otherwise compromised. SCE also has a pole loading program to assesses the strength of poles relative to specified “safety factors,” which are design standards intended to handle the structural load caused by wind, ice, and the weight of attached equipment. Poles that do not meet SCE’s or regulatory requirements for safety factors are documented and scheduled for either repair or replacement. In addition, poles may be identified for replacement during other utility work if they do not meet pole loading criteria when new equipment is added or if visual damage is identified by field personnel. SCE conducts these activities in its entire service territory. SCE does not consider these pole replacements to be a stand-alone WMP initiative or limited to HFRA; rather, pole replacements are part of SCE’s asset management activities.

8.2.3.1 Fire Resistant Wrap Expanded Deployment

Tracking ID: SH-19

Overview of activity: This new activity is a program that will focus on installing FR wraps on unwrapped wood poles on a risk-prioritized basis in HFRA that are located within areas experiencing the highest frequency of burns. See Table 8-1 for this activity’s targets.

Although wood poles themselves are generally not the source of ignition, installing a FR wrap can help the poles maintain structural integrity after a fire, which can prevent cascading failures of other poles, and reduce restoration time. FR wraps can also reduce the chance that the poles and conductor fall to the ground, even if the poles and/or conductor are damaged by a fire. SCE has received informal feedback from first responders that firefighting efforts and public egress are aided when poles and conductor are not on the ground because they might otherwise impede movement and logistics or increase the potential for contact with energized conductor.

Starting in 2026, SCE plans to expand the deployment of FR wraps in HFRA. FR wraps were previously used on structures that failed pole loading due to heavier covered conductor installation and therefore needed a new pole, and hence received a new pole with FR wrap installed.

This new activity will install FR wraps on unwrapped wooden poles that were not replaced when covered conductor was installed because they passed pole loading requirements. SCE will scope the program based on its Integrated Wildfire Mitigation Strategy (IWMS) risk framework, and primarily Severe Risk Areas with a high frequency of historical fires.

If factors outside of SCE’s control facilitate execution of additional units, SCE will strive to install up to 7,500 fire-resistant wraps on wood poles. This level of execution depends on exogenous factors like the issuance of permits and environmental clearances.

Impact of activity on wildfire risk:

The expected percent wildfire risk reduction/effectiveness, with level of granularity included, for the activity, including an explanation of the calculation, a list of assumptions, and justifications for each assumption.

Please see Table SCE 6-01 and Table 6-3 for mitigation effectiveness and risk reduction values. Table SCE 6-02 provides the basis for SCE's mitigation effectiveness assumptions. The calculations are explained in the narrative immediately following Table 6-3.

A trend analysis showing how implementation of the activity has reduced risk over time for each relevant risk and/or risk driver (e.g. vegetation contact for covered conductor installation).

SCE's prior installation of FR wrap poles was part of its covered conductor deployment, and while SCE does not have a formal trend analysis of its benefits, field observations and feedback from fire suppression agencies indicated its value in aiding fire suppression and restoration efforts.

A discussion of how the activity impacts the likelihood and consequence of ignitions.

Please see above. SCE notes that FR wrap applied to wooden poles can support fire suppression and service restoration, as it reduces the chance that a pole falls over in a fire, but it does not in itself directly reduce the potential for wildfire ignition.

Impact of activity on outage program risk:

The expected percent reliability risk reduction/effectiveness for the activity, including an explanation of the calculation, a list of assumptions, and justifications for each assumption. A risk reduction/effectiveness of 100% means no risk remains after the electrical corporation completes the activity.

This program does not affect outage program risk.

A discussion of how the electrical corporation considers and evaluates the hardened status of upstream circuits/segments/spans to determine the impact of the activity on reliability risk.

Please see above.

A discussion of how the activity impacts the likelihood and consequence of outage program events, including whether an area would still be subject to PSPS events after the electrical corporation completes the activity.

Please see above.

A discussion of how the activity impacts overall reliability, including how trends are being observed. This must include evaluation of number of outages occurring, the duration for those outages, and the number of customers affected during those outages.

Please see above.

Updates to the activity

A list of the changes the electrical corporation made to the activity since its last WMP submission.

N/A. This is a new program.

Justification for each of the changes, including references to lessons learned.

N/A.

A list of planned future improvements and/or updates to the activity, including a timeline for implementation.

N/A.

As applicable, a discussion of the status of any undergrounding work plans and progress, as required by Public Utilities Code section 8388.5(f)(2).

N/A.

As applicable, a discussion of any evaluations related to scoping grid hardening projects to account for future grid needs (e.g., load capacity, peak demand, system flexibility).

N/A.

Compatible initiatives:

- SH-1: Covered Conductor (Section 8.2.1.1)
- SH-14: Long Span Initiative (LSI) (Section 8.2.5.1)
- IN-1.1: Distribution HFRI Inspections (Section 8.3.1)
- IN-3: Distribution IR (Section 8.3.3)
- SH-17: REFCL (Ground Fault Neutralizer) (Section 8.2.6.1)
- SH-18: REFCL (Grounding Conversion) (Section 8.2.6.2)
- SH-5: Remote Controlled Automatic Reclosers (Section 8.2.8.1)
- VM-1: Hazard Tree Management Program (Section 9.2.3)
- VM-4: Dead and Dying Tree Removal (Section 9.2.4)
- VM-7: Distribution VM Clearances (Section 9.2.1)
- VM-2.1: Additional Structure Brushing (Section 9.4.1.2)
- VM-2.2: Compliance Structure Brushing (Section 9.4.1.1)
- SA-11: Early Fault Detection (EFD) (Chapter 10.3.1)
- SA-14: Distribution Open Phase Detection (DOPD) (Chapter 10.3.1)

8.2.4 Transmission Pole/Tower Replacements and Reinforcements

SCE's inspection and pole loading programs described above also drive transmission pole and tower replacements and reinforcements. In addition to those programs, SCE also has a Transmission Corrosion Program that assesses and remediates corroded transmission structures identified in SCE's transmission system. While the other inspection and pole loading programs apply to transmission poles and structures, this program focuses on all-steel structures across SCE's service territory, including out-of-state interties. The structures and lattice towers are mostly composed of galvanized, painted steel.

Aging steel structures may be at risk of failing due to environmental factors such as soil corrosivity and atmospheric corrosion that can affect the integrity of the structure. The corrosive environments can lead to rusting, pitting, and steel loss, thereby increasing the failing risk of the structures. Once a galvanized tower begins to corrode, the corrosion advances more quickly and can lead to steel loss and structure failures unless mitigated appropriately.

The Transmission Corrosion Program consists of assessment and mitigation of these structures. During the assessment phase, SCE performs above- and below-ground visual inspections and engineering analyses such as pitting depth, remaining steel thickness measurements, and soil sampling. In addition, SCE may perform bore scoping and ultrasonic testing on Light Weight Steel (LWS) poles to determine asset health in the future.

Mitigations depend on the assessment recommendations for each structure and may include, but are not limited to, installing concrete cap footings, replacing steel members, coating structures, engaging in cathodic protection, and, if necessary, replacing the structure.

SCE does not consider the pole and structure replacements and repairs to be a stand-alone WMP initiative or limited to HFRA; rather, they are part of SCE's asset management activities. Please refer to Section 8.4 for a discussion of Transmission remediations, including remediation of transition spans and Transmission IWMS Engineering Analysis and Testing in Section 8.2.12.1 for a discussion of these efforts.

8.2.5 Traditional Overhead Hardening

8.2.5.1 Long Span Initiative

Tracking ID: SH-14

Overview of the activity: SCE's Long Span Initiative (LSI) addresses increased risk of conductor clash in high wind conditions associated with distribution conductor spans of a certain length, spans with mixed conductor, spans that have a sharp angle, or spans that transition between vertical and horizontal configuration.

In 2020, SCE began using Light Detection and Ranging (LiDAR) on its distribution long spans to identify locations with potential conductor clash issues and planned to remediate the highest risk locations upon field validation. In 2022, SCE enhanced its risk methodology and prioritization by incorporating the IWMS and developing a risk analysis that considers LiDAR measurements, conductor probability of ignition (POI), and wind-related features to better target conductor clash scenarios.

Long spans that are at high risk for conductor clashing and that fall within locations that are consequential in the case of an ignition are prioritized for remediation. The type of remediation selected is determined by the specific details of each span and the corresponding field conditions.

This initiative includes three types of remediations that are carried out with the purpose of reducing conductor clashing risks from long spans:

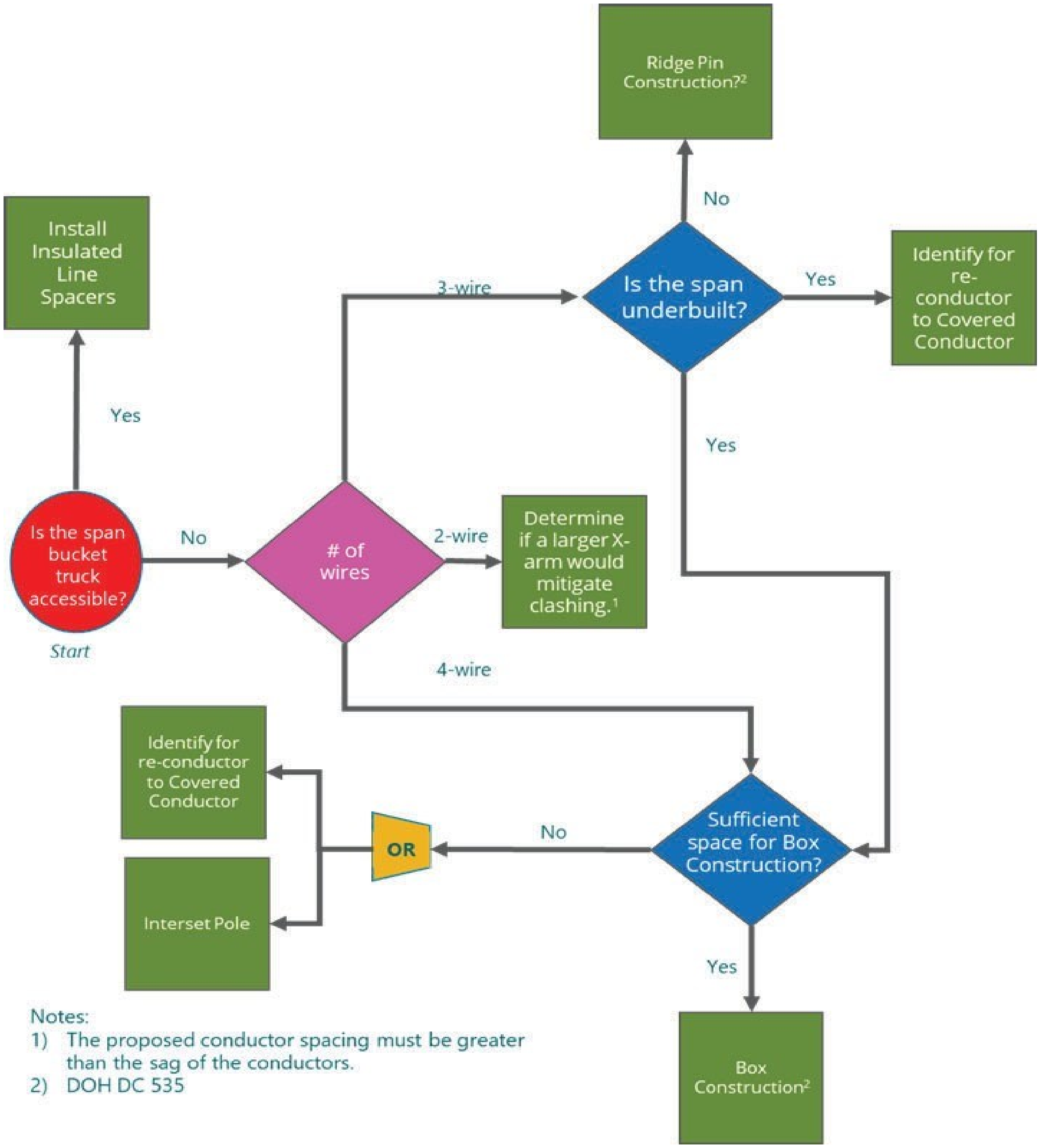
1. Line spacers: Insulated equipment that separates the lines to reduce the possibility of wire-to-wire contact. It is the preferred remediation type due to the speed of deployment and its effectiveness against clashing. Line spacers are used where there is bucket truck accessibility.

Figure SCE 8-05: A Line Spacer Installed on a Long Span to Mitigate Wire-to-Wire Contact (Left), Close Up Line Spacer View (Right)

2. Alternate Construction: This includes ridge pin, box construction, wider crossarms, and inter-set poles. These construction configurations increase phase spacing or reduce sag, minimizing the probability of wire-to-wire contact. This type of remediation is typically used when there is no bucket truck accessibility for line spacers.
3. Covered Conductor: The wire ensures that the lines are protected if clashing occurs. Covered conductor will be installed in instances where there is no bucket truck access and either a 3-wire span is underbuilt, or a 4-wire span does not have sufficient space for box construction.

The following flow chart summarizes how SCE makes a determination on the type of remediation appropriate for different scenarios.

Figure SCE 8-06: Long Span Initiative Remediation Decision Tree



See Table 8-1 for this activity's targets. SCE does not discuss a strive target for additional LSI units, as the activity target anticipates completing all remaining LSI scope in 2028.

Impact of activity on wildfire risk:

The expected percent wildfire risk reduction/effectiveness, with level of granularity included, for the activity, including an explanation of the calculation, a list of assumptions, and justifications for each assumption.

Please see Table SCE 6-01 and Table 6-3 for mitigation effectiveness and risk reduction values. Table SCE 6-02 provides the basis for SCE's mitigation effectiveness assumptions. The calculations are explained in the narrative immediately following Table 6-3.

A trend analysis showing how implementation of the activity has reduced risk over time for each relevant risk and/or risk driver (e.g. vegetation contact for covered conductor installation).

SCE reviewed data from 2019-2024. At locations where long spans were deployed, SCE observed 2 ignitions, compared with 11 ignitions at those locations prior to long span deployment. Because SCE takes a portfolio-level approach to deploying mitigations (as discussed in Section 6.1.3.2), the observed reduction in ignitions should not be interpreted to be a direct result of the deployment of this specific mitigation.

A discussion of how the activity impacts the likelihood and consequence of ignitions.

Please see the tables referenced above. SCE also notes that this mitigation does not reduce the consequence of ignitions, as its purpose is to reduce the ignition from occurring in the first place.

Impact of activity on outage program risk:

The expected percent reliability risk reduction/effectiveness for the activity, including an explanation of the calculation, a list of assumptions, and justifications for each assumption. A risk reduction/effectiveness of 100% means no risk remains after the electrical corporation completes the activity.

Please see Table SCE 6-01 and Table 6-3 for mitigation effectiveness and risk reduction values. Table SCE 6-02 provides the basis for SCE's mitigation effectiveness assumptions. The calculations are explained in the narrative immediately following Table 6-3

A discussion of how the electrical corporation considers and evaluates the hardened status of upstream circuits/segments/spans to determine the impact of the activity on reliability risk.

Upstream circuit status does not impact LSI's outage program impact.

A discussion of how the activity impacts the likelihood and consequence of outage program events, including whether an area would still be subject to PSPS events after the electrical corporation completes the activity.

Please see Table SCE 6- 1 and Table 6-3 for mitigation effectiveness and risk reduction values. The presence of LSl is not factored into SCE's decision-making process for PSPS.

A discussion of how the activity impacts overall reliability, including how trends are being observed. This must include evaluation of number of outages occurring, the duration for those outages, and the number of customers affected during those outages.

SCE does not have sufficient data to compare faults on spans with LSI to spans without LSI under similar conditions. However, because LSI reduces the potential for wire-to-wire contact, and therefore reduces the potential for faults, SCE anticipates that LSI would have a positive impact on reliability. SCE also notes that should an outage occur, the presence of LSI would not affect the duration of the outage.

Updates to the activity:

A list of the changes the electrical corporation made to the activity since its last WMP submission.

SCE does not plan changes to this program. Based on mitigations completed to date and anticipated remaining scope, SCE plans to be substantially finished with proactive long span initiative remediations in its HFRA by the end of this WMP cycle.

Justification for each of the changes, including references to lessons learned.

N/A.

A list of planned future improvements and/or updates to the activity, including a timeline for implementation.

N/A.

As applicable, a discussion of the status of any undergrounding work plans and progress, as required by Public Utilities Code section 8388.5(f)(2).

N/A.

As applicable, a discussion of any evaluations related to scoping grid hardening projects to account for future grid needs (e.g., load capacity, peak demand, system flexibility).

N/A.

Compatible initiatives:

- SH-19: FR Wrap Expanded Deployment (Section 8.2.3.1)
- IN-1.1: Distribution HFRI Inspections (Section 8.3.1)
- IN-3: Distribution IR (Section 8.3.3)
- SH-17: REFCL (Ground Fault Neutralizer) (Section 8.2.6.1)
- SH-18: REFCL (Grounding Conversion) (Section 8.2.6.2)
- SH-5: Remote Controlled Automatic Reclosers (Section 8.2.8.1)
- VM-7: Distribution VM Clearances (Section 9.2.1)
- VM-2.1: Additional Structure Brushing (Section 9.4.1.2)

- VM-2.2: Compliance Structure Brushing (Section 9.4.1.1)
- SA-11: Early Fault Detection (EFD) (Chapter 10.3.1)
- SA-14: Distribution Open Phase Detection (DOPD) (Chapter 10.3.1)

8.2.6 Emerging Grid Hardening Technology Installations and Pilots

8.2.6.1 Rapid Earth Fault Current Limiter – Ground Fault Neutralizers

Tracking ID: SH-17

Overview of activity: The Rapid Earth Fault Current Limiter (REFCL) initiative uses technology that detects ground faults as small as a half ampere on one phase of a three-phase powerline. This technology almost instantly reduces the voltage on the faulted conductor while boosting the voltage on the two remaining phases. This allows SCE to maintain service for customers while extinguishing arcs. SCE is using its REFCL program in HFRA to reduce the energy released from ground faults to mitigate the risk of an ignition.

SCE uses two approaches to implement REFCL technology: Ground Fault Neutralizer (SH-17) and Grounding Conversions (SH-18).

Ignitions caused by single phase to ground faults can be mitigated with the use of the Ground Fault Neutralizer (GFN), which reduces fault energy by a factor of a thousand or more compared to typical utility designs. A GFN can detect and act upon ground faults as small as a half ampere, making it substantially more sensitive than traditional protection.

The GFN is likely to be the preferred REFCL design for large substations. Large systems produce greater fault currents, which benefit more from the additional equipment used in a GFN project. Figure SCE 8-07 below shows an example of a GFN.

Figure SCE 8-07: Image of a Ground Fault Neutralizer

Since SCE's first GFN installation at Neenach substation in 2021, SCE has also in-serviced GFN systems at Acton and Phelan substation in 2024. This takes the total REFCL GFN-covered circuit miles to approximately 850 miles across 10 circuits for those three stations as of year-end 2024.

SCE provides additional details on its REFCL program in the workpaper titled, "Rapid Earth Fault Current Limiter (REFCL) Projects at Southern California Edison."[114] This report provides an overview of SCE's evaluation of REFCL and experience with the GFN at Neenach substation installed in 2021 as well as experience with three grounding conversion projects:

- An overhead isolation transformer installed in 2020 covering 2.5 miles of the Calstate 12kV circuit.
- A padmount isolation transformer covering 12 miles of the Corsair 12kV circuit in 2021.
- An Arc Suppression Coil to resonant ground Arrowhead substation, covering 40 miles of 12 kV circuitry, installed in 2021.

Additional details of REFCL can also be found in Section 10.3.1.6 Smart Meters: MADEC & Transformer EDD discussing Grid Monitoring systems.

See Table 8-1 for this activity's targets. If factors outside of SCE's control facilitate execution of additional units, SCE will strive to complete construction of Ground Fault Neutralizers at 12 substations in SCE's HFRA over the three-year period. This level of execution depends on exogenous factors like supply chain constraints.

Impact of activity on wildfire risk:

The expected percent wildfire risk reduction/effectiveness, with level of granularity included, for the activity, including an explanation of the calculation, a list of assumptions, and justifications for each assumption.

Please see Table SCE 6-01 and Table 6-3 for mitigation effectiveness and risk reduction values. Table SCE 6-02 provides the basis for SCE's mitigation effectiveness assumptions. The calculations are explained in the narrative immediately following Table 6-3.

A trend analysis showing how implementation of the activity has reduced risk over time for each relevant risk and/or risk driver (e.g. vegetation contact for covered conductor installation).

There have been zero observed ignitions due to drivers that REFCL GFN is intended to mitigate.[115]

A discussion of how the activity impacts the likelihood and consequence of ignitions.

Please see the tables referenced above. SCE also notes that this mitigation does not reduce the consequence of ignitions, as its purpose is to reduce the ignition from occurring in the first place.

114 See "Rapid Earth Fault Current Limiter (REFCL) Projects at Southern California Edison" workpaper, available at https://www.sce.com/wmp

115 One ignition observed in REFCL GFN areas was attributed to a mylar balloon, which is a phase-to-phase fault, whereas REFCL GFN is intended to mitigate phase-to-neutral faults.

Impact of activity on outage program risk:

The expected percent reliability risk reduction/effectiveness for the activity, including an explanation of the calculation, a list of assumptions, and justifications for each assumption. A risk reduction/effectiveness of 100% means no risk remains after the electrical corporation completes the activity.

Please see Table SCE 6-01 and Table 6-3 for mitigation effectiveness and risk reduction values. Table SCE 6-02 provides the basis for SCE's mitigation effectiveness assumptions. The calculations are explained in the narrative immediately following SCE has populated Table 6-3.

A discussion of how the electrical corporation considers and evaluates the hardened status of upstream circuits/segments/spans to determine the impact of the activity on reliability risk.

REFCL GFN is a mitigation applied at a substation, which then mitigates and protects all downstream circuitry within the grounding system of that substation. The hardening status of upstream circuits is not considered in the evaluation of its impact on reliability risk.

A discussion of how the activity impacts the likelihood and consequence of outage program events, including whether an area would still be subject to PSPS events after the electrical corporation completes the activity.

SCE does not consider the presence of REFCL in PSPS thresholds. SCE may revisit this approach as REFCL deployment expands and more experience is gained with the technology.

A discussion of how the activity impacts overall reliability, including how trends are being observed. This must include evaluation of number of outages occurring, the duration for those outages, and the number of customers affected during those outages.

Based on SCE's analysis at this time, SCE has not observed that REFCL installation has a measurable impact on reliability. From an engineering perspective, REFCL should improve reliability from momentary outages as the system is able to detect and clear them, resulting in an improvement relative to a non-REFCL situation. On the other hand, if the REFCL system detects larger faults, it may interrupt service for a larger portion of the circuit than if RECL was not present. As SCE gains more experience with REFCL systems installed with longer periods of activation, it will have more data on which to determine if REFCL has a measurable impact on reliability.

Updates to the activity:

A list of the changes the electrical corporation made to the activity since its last WMP submission.

SCE has not changed this program since its last WMP.

Justification for each of the changes, including references to lessons learned.

N/A.

A list of planned future improvements and/or updates to the activity, including a timeline for implementation.

N/A.

As applicable, a discussion of the status of any undergrounding work plans and progress, as required by Public Utilities Code section 8388.5(f)(2).

N/A.

As applicable, a discussion of any evaluations related to scoping grid hardening projects to account for future grid needs (e.g., load capacity, peak demand, system flexibility).

N/A.

Compatible initiatives:

- SH-1: Covered Conductor (Section 8.2.1.1)
- SH-14: Long Span Initiative (LSI) (Section 8.2.5.1)
- SH-16: Vibration Damper Retrofit (Section 8.2.1.2)
- SH-19: FR Wrap Expanded Deployment (Section 8.2.3.1)
- IN-1.1: Distribution HFRI Inspections (Section 8.3.1)
- IN-3: Distribution IR (Section 8.3.3)
- VM-1: Hazard Tree Management Program (Section 9.2.3)
- VM-4: Dead and Dying Tree Removal (Section 9.2.4)
- VM-7: Distribution VM Clearances (Section 9.2.1)
- VM-2.1: Additional Structure Brushing (Section 9.4.1.2)
- VM-2.2: Compliance Structure Brushing (Section 9.4.1.1)
- SH-2: Targeted Undergrounding in HFRA (Section 8.2.2.1)
- SA-11: Early Fault Detection (Chapter 10.3.1)

8.2.6.2 Rapid Earth Fault Current Limiter – Grounding Conversions

Tracking ID: SH-18

Overview of activity: The REFCL Grounding Conversion (REFCL GC) applications act to reduce energy and ignition risk associated with single phase to ground faults. SCE created a separate REFCL program for grounding conversion projects, which are used on smaller substations or applied at the distribution circuit level, rather than larger substations, which are targeted by the REFCL GFN program discussed in the immediately prior section. These projects convert the existing electric system to operate either ungrounded or resonant grounded without the use of the GFN. For the purposes of REFCL systems, the distinction between "large" and "small" substations/systems primarily depends on the lengths of overhead and underground circuitry. Typical grounding conversion projects cover 2 to 15 miles of circuitry.

Smaller substations produce lower fault current and resonant grounding alone can be used to reduce fault currents to help mitigate ignitions from ground faults. Grounding conversions for distribution circuitry outside of the substation is also possible in two variations: (1) the application of isolation transformers, and (2) the application of what SCE calls "pole tops.".

Figure SCE 8-08, below, provides typical example of an overhead isolation transformer application.

Figure SCE 8-08: Isolation (Iso) Bank Transformer (12kV to 12kV)

Figure SCE 8-9 below shows a pad-mounted isolation transformer installation. Overhead isolation transformer installations have a few limitations when compared to the pad-mounted alternative, with the main limitation being smaller sized equipment, which can limit the amount of customer load that can be converted to the REFCL scheme. The pad-mounted isolation transformers can be built much larger and therefore be applied to serve more customer load.

Figure SCE 8-9: Images of Isolation Transformers used for Grounding Conversion

See Table 8-1 for this activity's targets. If factors outside of SCE's control facilitate execution of additional units, SCE will strive to complete construction for grounding conversions at 18 locations in SCE's HFRA over the three-year period. This level of execution depends on exogenous factors like the supply chain constraints and the issuance of permits and environmental clearances.

Impact of activity on wildfire risk:

The expected percent wildfire risk reduction/effectiveness, with level of granularity included, for the activity, including an explanation of the calculation, a list of assumptions, and justifications for each assumption.

Please see Table SCE 6-01 and Table 6-3 for mitigation effectiveness and risk reduction values. Table SCE 6-02 provides the basis for SCE's mitigation effectiveness assumptions. The calculations are explained in the narrative immediately following Table 6-3 .

A trend analysis showing how implementation of the activity has reduced risk over time for each relevant risk and/or risk driver (e.g. vegetation contact for covered conductor installation).

There were three historical ignitions associated with circuits before REFCL GC implementation. Post-REFCL GC implementation, no ignitions have been identified on these same circuits.

A discussion of how the activity impacts the likelihood and consequence of ignitions.

Please see the tables referenced above. SCE also notes that this mitigation does not reduce the consequence of ignitions, as its purpose is to reduce the ignition from occurring in the first place.

Impact of activity on outage program risk:

The expected percent reliability risk reduction/effectiveness for the activity, including an explanation of the calculation, a list of assumptions, and justifications for each assumption. A risk reduction/effectiveness of 100% means no risk remains after the electrical corporation completes the activity.

Please see Table SCE 6-01 and Table 6-3 for mitigation effectiveness and risk reduction values. Table SCE 6-02 provides the basis for SCE's mitigation effectiveness assumptions. The calculations are explained in the narrative immediately following Table 6-3.

A discussion of how the electrical corporation considers and evaluates the hardened status of upstream circuits/segments/spans to determine the impact of the activity on reliability risk.

REFCL GC is applied at either at an isolation transformer or a pole-top, which then mitigates and protects all downstream circuitry within the grounding system. The hardening status of upstream circuits is not considered in the evaluation of its impact on reliability risk.

A discussion of how the activity impacts the likelihood and consequence of outage program events, including whether an area would still be subject to PSPS events after the electrical corporation completes the activity.

SCE does not currently factor the presence of REFCL into PSPS thresholds. SCE may revisit this approach as REFCL deployment expands and more experience is gained with the technology.

A discussion of how the activity impacts overall reliability, including how trends are being observed. This must include evaluation of number of outages occurring, the duration for those outages, and the number of customers affected during those outages.

Please see the discussion in the previous section on REFCL GNF.

Updates to the activity:

A list of the changes the electrical corporation made to the activity since its last WMP submission.

SCE has decided to not continue with resonant grounding of substations without a Residual Current Compensator. The demonstration at Arrowhead substation was unable to achieve the desired level of performance and will be converted to a GFN. Resonant grounding will still be performed on distribution isobanks and poletops where the small size allows for similar performance.

Justification for each of the changes, including references to lessons learned.

See above.

A list of planned future improvements and/or updates to the activity, including a timeline for implementation.

N/A.

As applicable, a discussion of the status of any undergrounding work plans and progress, as required by Public Utilities Code section 8388.5(f)(2).

N/A.

As applicable, a discussion of any evaluations related to scoping grid hardening projects to account for future grid needs (e.g., load capacity, peak demand, system flexibility).

N/A.

Compatible initiatives: Please see the list above for SH-17 (Section 8.2.6.1).

8.2.6.3 Transmission High Risk Transition Spans

Tracking ID: 8.2.6.3

Overview of activity: SCE is piloting this activity in 2026 to determine its scope and approach to establish it as a WMP activity for 2027-2028. Transition spans are conductor spans on the transmission system where the conductor changes orientation from a horizontal to vertical configuration, or vice versa. These spans are more susceptible to wire-to-wire contact under certain situations such as high wind or vehicle-hit-structure.

Mitigations vary by location but may include increasing conductor phase spacing by re-arranging the pole-head configuration, inter-set poles to decrease the span length, pole structures that will accommodate larger phase clearances, and line spacers to reduce risks where transition spans are identified. SCE will pilot this program over the WMP period and scope will be based on inspection results following engineering analysis. Mitigation deployment will be informed by IWMS prioritization with considerations to operational feasibility.

SCE's Transmission HFRI inspection program (IN-1.2) includes questions that are intended to identify locations of transition spans for potential remediation pending further engineering and risk analysis. This has yielded potential locations that SCE will evaluate in 2026, including potentially performing mitigations in 2026. As noted above, based on 2026 findings and learnings, SCE is considering establishing a program in 2027-2028 to remediate transmission high-risk transmission spans.

Impact of activity on wildfire risk:

The expected percent wildfire risk reduction/effectiveness, with level of granularity included, for the activity, including an explanation of the calculation, a list of assumptions, and justifications for each assumption.

As this is a new pilot, the impact of the activity on wildfire risk is not yet available. However, SCE expects these mitigations to mitigate the risk of wire-to-wire contact, yielding a lower likelihood of fault and ignition.

A trend analysis showing how implementation of the activity has reduced risk over time for each relevant risk and/or risk driver (e.g. vegetation contact for covered conductor installation).

A trend analysis is not available for this new activity.

A discussion of how the activity impacts the likelihood and consequence of ignitions.

Please see above.

Impact of activity on outage program risk:

The expected percent reliability risk reduction/effectiveness for the activity, including an explanation of the calculation, a list of assumptions, and justifications for each assumption. A risk reduction/effectiveness of 100% means no risk remains after the electrical corporation completes the activity.

As this is a new activity, SCE does not have a sufficient basis on which to forecast its impact on outage risk. As this activity mitigates against wire-to-wire contact, it would reduce faults, which can potentially reduce outages.

A discussion of how the electrical corporation considers and evaluates the hardened status of upstream circuits/segments/spans to determine the impact of the activity on reliability risk.

Upstream and downstream circuit conditions do not affect the decision to mitigate high risk transition spans as the vertical/horizontal configuration at a pole is the driver for reliability risk.

A discussion of how the activity impacts the likelihood and consequence of outage program events, including whether an area would still be subject to PSPS events after the electrical corporation completes the activity.

This activity does not impact outage program events. Remediated circuits could still be subject to PSPS events.

A discussion of how the activity impacts overall reliability, including how trends are being observed. This must include evaluation of number of outages occurring, the duration for those outages, and the number of customers affected during those outages.

This activity is intended to reduce faults, and therefore would have a positive impact on reliability. SCE also notes that similar to the LSI, it would not affect outage duration should an outage occur.

Updates to the activity:

A list of the changes the electrical corporation made to the activity since its last WMP submission.

N/A. This is a new pilot.

Justification for each of the changes, including references to lessons learned.

N/A.

A list of planned future improvements and/or updates to the activity, including a timeline for implementation.

N/A.

As applicable, a discussion of the status of any undergrounding work plans and progress, as required by Public Utilities Code section 8388.5(f)(2).

N/A.

As applicable, a discussion of any evaluations related to scoping grid hardening projects to account for future grid needs (e.g., load capacity, peak demand, system flexibility).

N/A.

Compatible initiatives:

- SH-20: Transmission Proactive Splice Shunting (Section 8.2.6.4)
- IN-1.2: Transmission HFRI Inspections (Section 8.3.2)
- IN-4: Transmission IR and Corona (Section 8.3.3)
- VM-8: Transmission VM Clearances (Section 9.2.2)
- VM-2.1: Additional Structure Brushing (Section 9.4.1.2)
- VM-2.2: Compliance Structure Brushing (Section 9.4.1.1)

8.2.6.4 Transmission Proactive Splice Shunting

Tracking ID: SH-20

Overview of the activity: Splices can fail due to age, weather, contact from object, and other factors that can lead to wires down. SCE's historical X-ray inspections performed on transmission splices in HFRA produced roughly a 55% notification rate (i.e., splice exhibited signs of nonconformance to original installation specification, improper crimping, etc.). Because of this, going forward, SCE plans to proactively remediate splices by shunting them, which adds redundancy to the splice by carrying both physical and electrical load. Remediation scope is informed by IWMS risk tranche categories and lines with conductor sizes that have demonstrated higher notification rate, with considerations given to operational feasibility.

In 2026, SCE will initiate its proactive splice shunting program. During this ramp up year, SCE will evaluate its splice shunting capacity considering factors such as outages, materials, and external resources, while continuing to assess transmission system risks. The targets for 2027 and 2028 will be established based on learnings from 2025 and 2026.

Impact of activity on wildfire risk:

The expected percent wildfire risk reduction/effectiveness, with level of granularity included, for the activity, including an explanation of the calculation, a list of assumptions, and justifications for each assumption.

Please see Table SCE 6-01 and Table 6-3 for mitigation effectiveness and risk reduction values. Table SCE 6-02 provides the basis for SCE's mitigation effectiveness assumptions. The calculations are explained in the narrative immediately following Table 6-3.

A trend analysis showing how implementation of the activity has reduced risk over time for each relevant risk and/or risk driver (e.g. vegetation contact for covered conductor installation).

As this is a new activity, there are no historic trends to analyze.

A discussion of how the activity impacts the likelihood and consequence of ignitions.

Please see above. SCE also notes that this mitigation does not reduce the consequence of ignitions, as its purpose is to reduce the ignition from occurring in the first place.

Impact of activity on outage program risk:

The expected percent reliability risk reduction/effectiveness for the activity, including an explanation of the calculation, a list of assumptions, and justifications for each assumption. A risk reduction/effectiveness of 100% means no risk remains after the electrical corporation completes the activity.

SCE has not modeled its effect on outage risk due to a lack of observed field data. As the program matures with increased field deployment, SCE will have a greater basis for evaluation. As the program mitigates against splice failure, SCE anticipates it would have a positive impact on reliability.

A discussion of how the electrical corporation considers and evaluates the hardened status of upstream circuits/segments/spans to determine the impact of the activity on reliability risk.

Upstream and downstream circuit conditions do not affect the decision to shunt splices as the splice itself is the driver for reliability risk.

A discussion of how the activity impacts the likelihood and consequence of outage program events, including whether an area would still be subject to PSPS events after the electrical corporation completes the activity.

This activity does not affect outage program events. Remediated circuits could still be subject to PSPS events.

A discussion of how the activity impacts overall reliability, including how trends are being observed. This must include evaluation of number of outages occurring, the duration for those outages, and the number of customers affected during those outages.

A trend analysis is not available for this new activity. As noted above, SCE anticipates it would have a positive impact on reliability, as it would reduce the potential for splice failure.

Updates to the activity:

A list of the changes the electrical corporation made to the activity since its last WMP submission.

While this is a new program, please see below for context.

Justification for each of the changes, including references to lessons learned.

In SCE's 2025 WMP Update, SCE stated that, "SCE intends to continue IN-9b [the transmission splice x-ray inspection program] with a 2025 compliance target of 50 inspections and a 2025 strive target of 100 inspections, based on the value of the results of this program in results observed to date."[116] SCE also notes that Energy Safety issued ACI SCE-25U-05 in the decision approving SCE's 2025 WMP Update, saying that, "SCE must also discuss its plan to mitigate the risks associated with its transmission splices."

In light of the ACI, and due to the find rate, SCE intends to move forward with splice shunting on a proactive basis and to forego the inspection.

SCE did not finalize this decision until early 2025, while developing its 2026-2028 WMP, which is why SCE is presenting an updated approach in this 2026-2028 WMP that was not reflected in the 2025 WMP Update.

A list of planned future improvements and/or updates to the activity, including a timeline for implementation.

N/A.

As applicable, a discussion of the status of any undergrounding work plans and progress, as required by Public Utilities Code section 8388.5(f)(2).

N/A.

As applicable, a discussion of any evaluations related to scoping grid hardening projects to account for future grid needs (e.g., load capacity, peak demand, system flexibility).

N/A.

Compatible initiatives: N/A; this activity is in not used in combination with other activities to increase risk reduction effectiveness.

116 SCE 2025 WMP Update, page 28.

8.2.7 Microgrids

8.2.7.1 Microgrids

Tracking ID: N/A

Overview of the activity:

Other than remote grids, which is a specific type of microgrid, SCE is not actively pursuing microgrids as a wildfire-specific mitigation at this time. Please see Section 8.2.9 for more information about remote grid efforts.

SCE undertook microgrid assessment studies to understand the feasibility of microgrid deployment. The results were presented in the 2023-2025 SCE WMP. That effort originally focused on two activities: 1) produce a study evaluating sites that are subject to frequent PSPS events to determine which sites would benefit from having a microgrid that provides backup power during de-energizations, and 2) if any sites were found to be cost-effective, engaging the property owners of those sites with a proposal to install a microgrid at the location to support community resilience to PSPS events.

The initial assessments concluded that microgrids were not cost-effective when comparing the net cost for installing the microgrid to the value of service provided by the microgrid.

SCE notes that it is participating in the Microgrid OIR (R.19-09-009), which is relevant to microgrids in SCE's service territory and not as a SCE wildfire initiative.

Impact of activity on wildfire risk:

The expected percent wildfire risk reduction/effectiveness, with level of granularity included, for the activity, including an explanation of the calculation, a list of assumptions, and justifications for each assumption.

N/A. Please see above.

A trend analysis showing how implementation of the activity has reduced risk over time for each relevant risk and/or risk driver (e.g. vegetation contact for covered conductor installation).

N/A. Please see above.

A discussion of how the activity impacts the likelihood and consequence of ignitions

N/A. Please see above.

Impact of activity on outage program risk:

N/A. Please see above.

The expected percent reliability risk reduction/effectiveness for the activity, including an explanation of the calculation, a list of assumptions, and justifications for each assumption. A risk reduction/effectiveness of 100% means no risk remains after the electrical corporation completes the activity.

N/A. Please see above.

A discussion of how the electrical corporation considers and evaluates the hardened status of upstream circuits/segments/spans to determine the impact of the activity on reliability risk.

N/A. Please see above.

A discussion of how the activity impacts the likelihood and consequence of outage program events, including whether an area would still be subject to PSPS events after the electrical corporation completes the activity.

N/A. Please see above.

A discussion of how the activity impacts overall reliability, including how trends are being observed. This must include evaluation of number of outages occurring, the duration for those outages, and the number of customers affected during those outages.

N/A. Please see above.

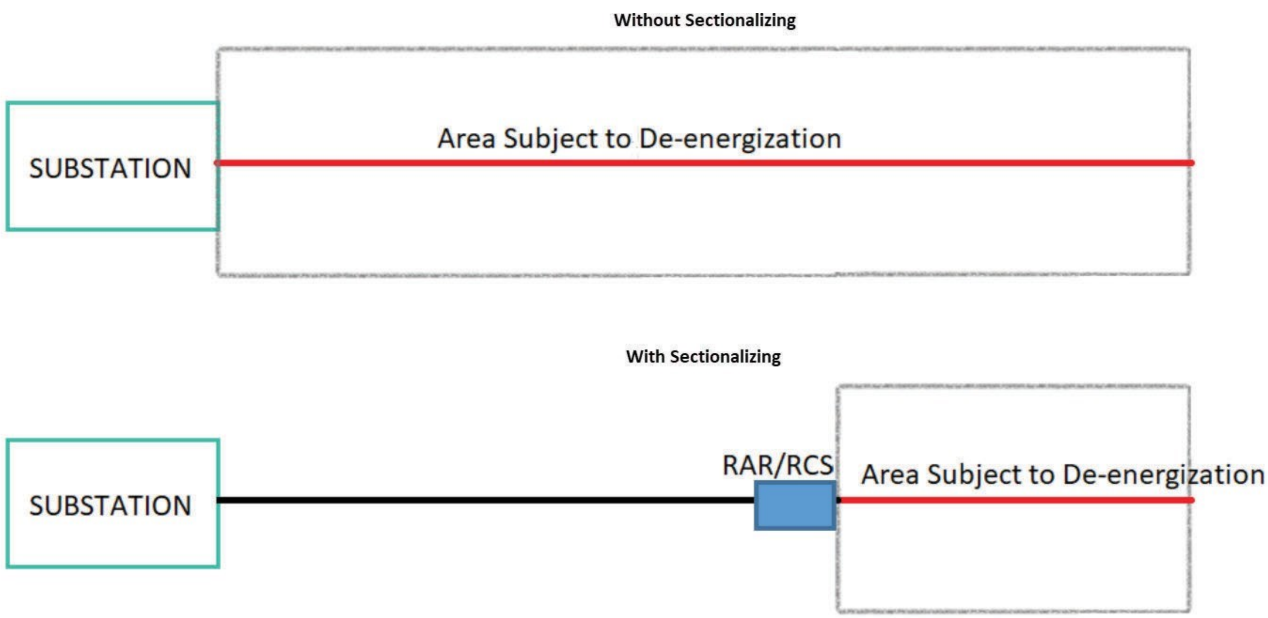
8.2.8 Installation of System Automation Equipment

8.2.8.1 Remote Controlled Automatic Reclosers

Tracking ID: SH-5

Overview of activity: SH-5 is a program to install Remote Control Switches (RCS) and Remote Automatic Recloser (RAR) devices. Distribution circuits span many miles, may traverse areas of varying risk, and are subject to varying weather conditions based on specific asset locations. During PSPS events, both the portions of circuits that do not pose ignition risks and the portions that present ignition risks may be de-energized, if there are no available means of isolating these segments to only de-energize portions of concern. RCS and RARs devices to help sectionalize circuits and control the flow of electricity remotely.

Figure SCE 8-10: Sectionalizing Devices Limit De-energization to Smaller Segments



RCS

RCS are a type of load sectionalization device that helps SCE limit PSPS de-energization to fewer and smaller circuit segments. Manual switches increase the time and resources needed for de-energization, testing, and re-energization. The remote-control capabilities of RCS allow SCE to quickly respond to emergent fire danger conditions to reduce ignition driver risks and minimize the effects of PSPS events.

RARs

RARs are a type of fault-interrupting automatic switch that shuts off electric power when an electrical fault or short circuit is detected, thus reducing the risk of ignition. RARs are reclosers that have been modified to be remotely operated by means of a radio. They operate in a similar fashion to a substation circuit breaker but are located on distribution line sections remote from the substation.

New RARs and RCSs are intended to further sectionalize circuits and circuit segments and improve SCE's ability to reduce PSPS scope, isolate faults and improve restoration time. SCE increases the fault sensitivity of RARs by way of operational settings during adverse weather conditions.

See Table 8-1 for this activity's targets. If future PSPS de-energization impacts effect more circuits than anticipated and justify the execution of additional units, SCE will strive to install 51 RAR/RCS sectionalizing devices over the three-year period, subject to needs based on previous years.

Impact of activity on wildfire risk:

The expected percent wildfire risk reduction/effectiveness, with level of granularity included, for the activity, including an explanation of the calculation, a list of assumptions, and justifications for each assumption.

Please see Table SCE 6-01 and Table 6-3 for mitigation effectiveness and risk reduction values. Table SCE 6-02 provides the basis for SCE's mitigation effectiveness assumptions. The calculations are explained in the narrative immediately following Table 6-3.

A trend analysis showing how implementation of the activity has reduced risk over time for each relevant risk and/or risk driver (e.g. vegetation contact for covered conductor installation).

The RARs and RCS that will be installed for 2026-2028 are primarily scoped on the basis of mitigating PSPS. As an additional benefit, Fast Curve settings that are enabled on RARs can reduce response time to protect the line from fault currents when they occur, thereby reducing ignition risk.

A discussion of how the activity impacts the likelihood and consequence of ignitions.

Please see the tables referenced above. SCE also notes that this mitigation does not reduce the consequence of ignitions, as its purpose is to reduce the ignition from occurring in the first place.

Impact of activity on outage program risk:

The expected percent reliability risk reduction/effectiveness for the activity, including an explanation of the calculation, a list of assumptions, and justifications for each assumption. A risk reduction/effectiveness of 100% means no risk remains after the electrical corporation completes the activity.

Please see Table SCE 6-01 and Table 6-3 for mitigation effectiveness and risk reduction values. Table SCE 6-02 provides the basis for SCE's mitigation effectiveness assumptions. The calculations are explained in the narrative immediately following Table 6-3.

A discussion of how the electrical corporation considers and evaluates the hardened status of upstream circuits/segments/spans to determine the impact of the activity on reliability risk.

When SCE performs engineering analysis of PSPS de-energizations, upstream conditions are often directly relevant to this activity and are often a driver of new RAR installation. For instance, if upstream circuit segments are fully covered and could benefit from raised PSPS wind speed thresholds but are subject to lowest common denominator thresholds from downstream segments, an RAR can be installed to isolate the bare wire and allow the covered sections to remain online if the bare portion is de-energized.

A discussion of how the activity impacts the likelihood and consequence of outage program events, including whether an area would still be subject to PSPS events after the electrical corporation completes the activity.

RARs and RCSs allow SCE to sectionalize circuits into smaller segments during PSPS and thus reduce the scope and size of PSPS.

A discussion of how the activity impacts overall reliability, including how trends are being observed. This must include evaluation of number of outages occurring, the duration for those outages, and the number of customers affected during those outages.

Please see Section 8.7.1 for a discussion of the impact of RARs and RCSs on reliability, including tables with customer impacts.

Updates to the activity:

A list of the changes the electrical corporation made to the activity since its last WMP submission.

SCE has not changed this program since its last WMP.

Justification for each of the changes, including references to lessons learned.

N/A.

A list of planned future improvements and/or updates to the activity, including a timeline for implementation.

N/A.

As applicable, a discussion of the status of any undergrounding work plans and progress, as required by Public Utilities Code section 8388.5(f)(2).

N/A.

As applicable, a discussion of any evaluations related to scoping grid hardening projects to account for future grid needs (e.g., load capacity, peak demand, system flexibility).

N/A.

Compatible initiatives:

- SH-1: Covered Conductor (Section 8.2.1.1)
- SH-14: Long Span Initiative (LSI) (Section 8.2.5.1)
- SH-19: FR Wrap Expanded Deployment (Section 8.2.3.1)
- IN-1.1: Distribution HFRI Inspections (Section 8.3.1)
- IN-3: Distribution IR (Section 8.3.3)
- SH-17: REFCL (Ground Fault Neutralizer) (Section 8.2.6.1)
- SH-18: REFCL (Grounding Conversion) (Section 8.2.6.2)
- SH-5: Remote Controlled Automatic Reclosers (Section 8.2.8.1)
- VM-1: Hazard Tree Management Program (Section 9.2.3)
- VM-4: Dead and Dying Tree Removal (Section 9.2.4)
- VM-7: Distribution VM Clearances (Section 9.2.1)
- VM-2.1: Additional Structure Brushing (Section 9.4.1.2)
- VM-2.2: Compliance Structure Brushing (Section 9.4.1.1)

- SA-11: Early Fault Detection (EFD) (Chapter 10.3.1)
- SA-14: Distribution Open Phase Detection (DOPD) (Chapter10.3.1)

8.2.9 Line Removal (in the HFTD)

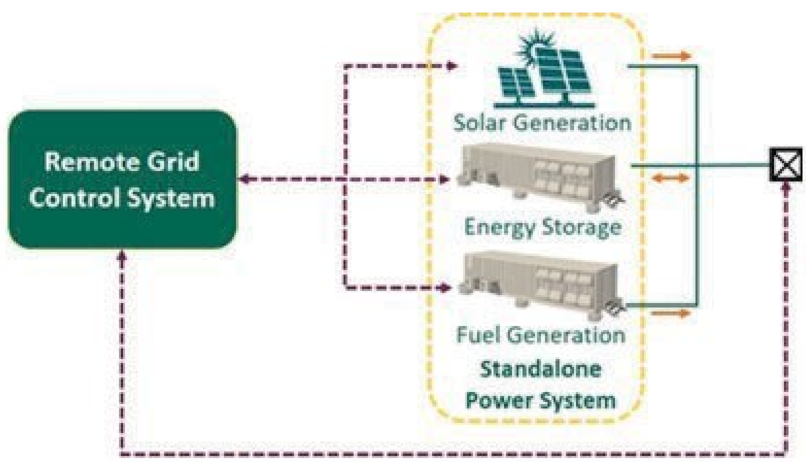
In 2025, SCE will assess and disconnect, or remove as appropriate, energized idle distribution facilities in HFRA and HFRA-adjacent areas. This activity will extend to, and may include transmission in, 2026.

8.2.9.1 Remote Grid Feasibility Study for Wildfire Reduction

Tracking ID: 8.2.9.1

Overview of the Activity: SCE is evaluating several potential remote grid projects for the 2026-2028 timeframe. A remote grid is a configuration where a small number of customers in remote locations are served entirely by local Distributed Energy Resources (DERs) that are disconnected from the SCE grid, as shown in Figure SCE 8-11. These are a type of microgrid, without the option to be connected to the larger grid.

Figure SCE 8-11: Remote Grid System Diagram



Remote grid systems are composed of solar PV, battery energy storage, backup fuel generator and grid system controller to form a permanent islanded power system co-located with the customer loads. Customers in remote areas with relatively small and steady load (typically < 100 kW) can potentially be served by remote grids, allowing for improved resiliency by isolating the customer loads from other portions of the grid where ignitions or faults may occur (i.e., the overhead portion of the grid serving those customers). As SCE's IWMS identifies undergrounding line segments in severe risk areas where there are egress constraints and other high-risk criteria, remote grids may be a viable alternative to reducing ignition risk in select cases where undergrounding of distribution lines are infeasible or very expensive (see Section 8.2.2 for a discussion of SCE's undergrounding initiatives).

There are potential additional benefits, such as reduced vegetation management and inspection work, because the long lines that connect the customer load to the rest of the grid will be removed. A related activity is the Microgrid Assessment discussed in Section 8.2.7.1.

SCE is evaluating locations for potential remote grids where undergrounding is infeasible and the ratio of line length to load appears to be relatively high. This list was further refined using SCE's IWMS risk tranches to prioritize locations in Severe Risk Areas. From this review process, SCE has identified 16 total locations that meet the criteria. Three of these 16 sites are still underway for technical feasibility assessment. Of the remaining 13 sites, four appear technically feasible and remain under review for permitting, land acquisition, and financial evaluation.

Impact of activity on wildfire risk:

The expected percent wildfire risk reduction/effectiveness, with level of granularity included, for the activity, including an explanation of the calculation, a list of assumptions, and justifications for each assumption.

A remote grid would remove overhead lines and thus remove the risk of wildfire from those overhead lines.

A trend analysis showing how implementation of the activity has reduced risk over time for each relevant risk and/or risk driver (e.g. vegetation contact for covered conductor installation).

SCE has not yet implemented remote grids; it is still under development.

A discussion of how the activity impacts the likelihood and consequence of ignitions.

Please see above. SCE also notes that this mitigation does not reduce the consequence of ignitions, as its purpose is to reduce the ignition from occurring in the first place.

Impact of activity on outage program risk:

The expected percent reliability risk reduction/effectiveness for the activity, including an explanation of the calculation, a list of assumptions, and justifications for each assumption. A risk reduction/effectiveness of 100% means no risk remains after the electrical corporation completes the activity.

A remote grid would eliminate PSPS risk to a particular location because that location would no longer be connected to SCE's grid. SCE would also intend for the remote grid to meet or exceed existing reliability performance.

A discussion of how the electrical corporation considers and evaluates the hardened status of upstream circuits/segments/spans to determine the impact of the activity on reliability risk.

See above.

A discussion of how the activity impacts the likelihood and consequence of outage program events, including whether an area would still be subject to PSPS events after the electrical corporation completes the activity.

See above.

A discussion of how the activity impacts overall reliability, including how trends are being observed. This must include evaluation of number of outages occurring, the duration for those outages, and the number of customers affected during those outages.

See above.

Updates to the activity:

A list of the changes the electrical corporation made to the activity since its last WMP submission.

Please see above for the description of SCE's status. SCE continues to progress from studies to more in-depth analysis of potential implementation.

Justification for each of the changes, including references to lessons learned.

N/A.

A list of planned future improvements and/or updates to the activity, including a timeline for implementation.

N/A.

As applicable, a discussion of the status of any undergrounding work plans and progress, as required by Public Utilities Code section 8388.5(f)(2).

N/A.

As applicable, a discussion of any evaluations related to scoping grid hardening projects to account for future grid needs (e.g., load capacity, peak demand, system flexibility).

N/A.

Compatible initiatives: This activity is not used in combination with other activities.

8.2.10 Other Grid Topology Improvements to Minimize Risk of Ignitions

SCE does not have any additional activities to report for this section.

8.2.11 Other Grid Topology to Mitigate or Reduce PSPS Events

SCE does not have any additional activities to report for this section.

8.2.12 Other Technologies and Systems Not Listed Above

8.2.12.1 Transmission Integrated Wildfire Mitigation Strategy (IWMS) Engineering Analysis and Testing

Tracking ID: 8.2.12.1

Overview of activity: In SCE's 2023-2025 WMP, SCE stated that it intended to "Perform assessments of transmission hardening options and develop potential pilots/programs (contingent upon results of assessments)."[117] The planned completion date for this effort was December 2025, and it is underway at the time SCE is submitting this 2026-2028 WMP in March 2025.

SCE plans to continue to assess the costs and feasibility of potential mitigation options for its transmission facilities. The higher voltages of transmission lines can make it more challenging and costly to use the same conventional hardening mitigations used for distribution facilities, such as targeted undergrounding or covered conductor. There are also fewer examples of other utilities that have implemented these types of mitigations for transmission facilities, making the evaluation process more difficult.

SCE's objective is to identify hardening options for transmission facilities and to determine which options, if any, should be studied further via a pilot or limited deployment. In addition to hardening options, SCE may evaluate changes to transmission inspections and transmission-related risk analyses.

SCE will also assess its current strategy and approach towards mitigating risk from its idle transmission facilities, taking into account the experiences and approaches of the other IOUs, and make changes if appropriate. SCE currently inspects its idle transmission facilities in HFRA at the same frequency as its energized transmission facilities. SCE will have completed its grounding mitigation for idle transmission lines that parallel energized transmission lines in HFRA in 2025 and will complete its grounding mitigation for idle transmission lines in non-HFRA and idle transmission lines that do not parallel other transmission lines in HFRA in 2026.

Impact of activity on wildfire risk:

The expected percent wildfire risk reduction/effectiveness, with level of granularity included, for the activity, including an explanation of the calculation, a list of assumptions, and justifications for each assumption.

This is a study and is intended to better understand impacts to wildfire and outage risk from potential mitigations.

A trend analysis showing how implementation of the activity has reduced risk over time for each relevant risk and/or risk driver (e.g. vegetation contact for covered conductor installation).

See above.

A discussion of how the activity impacts the likelihood and consequence of ignitions.

See above.

Impact of activity on outage program risk:

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117 SCE 2023-2025 WMP, Section 8.1.1.1, Table 8-1, page 232.

The expected percent reliability risk reduction/effectiveness for the activity, including an explanation of the calculation, a list of assumptions, and justifications for each assumption. A risk reduction/effectiveness of 100% means no risk remains after the electrical corporation completes the activity.

See above.

A discussion of how the electrical corporation considers and evaluates the hardened status of upstream circuits/segments/spans to determine the impact of the activity on reliability risk.

See above.

A discussion of how the activity impacts the likelihood and consequence of outage program events, including whether an area would still be subject to PSPS events after the electrical corporation completes the activity.

See above.

A discussion of how the activity impacts overall reliability, including how trends are being observed. This must include evaluation of number of outages occurring, the duration for those outages, and the number of customers affected during those outages.

See above.

Updates to the activity:

A list of the changes the electrical corporation made to the activity since its last WMP submission.

As noted above, this activity originated in SCE's 2023-2025 WMP. To the extent that it results in areas for further evaluation or piloting, SCE would introduce those in a future WMP submission.

Justification for each of the changes, including references to lessons learned.

N/A.

A list of planned future improvements and/or updates to the activity, including a timeline for implementation.

N/A.

As applicable, a discussion of the status of any undergrounding work plans and progress, as required by Public Utilities Code section 8388.5(f)(2).

N/A.

As applicable, a discussion of any evaluations related to scoping grid hardening projects to account for future grid needs (e.g., load capacity, peak demand, system flexibility).

N/A.

Compatible initiatives: It is possible that the study will identify feasible mitigations that would be complimentary with existing mitigations.

8.2.13 Status Updates on Additional Technologies Being Piloted

8.2.13.1 Transmission Enhanced System Design

Tracking ID: 8.2.13.1

Overview of activity: SCE is enhancing its subtransmission system to further reduce wildfire hazards. Enhanced System Design (ESD) is a cost-effective, long-term hardening pilot that SCE intends to implement on 66kV structures in Severe Risk Areas to mitigate the risk of ignitions on subtransmission lines. In 2024, SCE updated engineering standards to ensure traditional pole replacement programs incorporate ESD design, preventing future rework. SCE plans to apply ESD on 66kV structures with learnings to inform future hardening strategy.

The updated engineering standards for 66kV will use 115kV design criteria and incorporate steel structures like Tubular Steel Pole (TSP) or Light Weight Steel (LWS) where feasible. These revised standards will help reduce wildfire risks by ensuring sufficient cross-arm spacing per 115kV design criteria while utilizing more resilient TSP or LWS structures to reduce potential issues resulting from contact from object, which were the main causes of 66kV ignition events since 2019.

Impact of activity on wildfire risk:

The expected percent wildfire risk reduction/effectiveness, with level of granularity included, for the activity, including an explanation of the calculation, a list of assumptions, and justifications for each assumption.

Transmission ESD would reduce the probability of ignition for most of the sub-drivers associated ignitions on the sub-transmission system, especially Contact from Foreign Object (CFO) and Equipment Failure (EFF).

A trend analysis showing how implementation of the activity has reduced risk over time for each relevant risk and/or risk driver (e.g. vegetation contact for covered conductor installation).

A trend analysis is not available for this new activity.

A discussion of how the activity impacts the likelihood and consequence of ignitions.

Increased spacing between phases helps minimize the risk of ignition from foreign objects that might bridge conductor phases and wire to wire contact. Additionally, higher insulation requirements reduce the ignition risk from energized phase conductor and ground.

Impact of activity on outage program risk:

The expected percent reliability risk reduction/effectiveness for the activity, including an explanation of the calculation, a list of assumptions, and justifications for each assumption. A risk reduction/effectiveness of 100% means no risk remains after the electrical corporation completes the activity.

Transmission ESD does not have a direct impact on outage programs, but may result in fewer faults and consequently, fewer outages.

A discussion of how the electrical corporation considers and evaluates the hardened status of upstream circuits/segments/spans to determine the impact of the activity on reliability risk.

Transmission ESD has no impact to upstream circuits.

A discussion of how the activity impacts the likelihood and consequence of outage program events, including whether an area would still be subject to PSPS events after the electrical corporation completes the activity.

Transmission ESD has no impact on PSPS protocols.

A discussion of how the activity impacts overall reliability, including how trends are being observed. This must include evaluation of number of outages occurring, the duration for those outages, and the number of customers affected during those outages.

SCE anticipates that the overall reliability of the 66kV voltage system will increase with application of Transmission ESD criteria because increased phase spacing and use of more resilient structures may result in fewer faults and outages.

Updates to the activity:

A list of the changes the electrical corporation made to the activity since its last WMP submission.

N/A. This is a new pilot.

Justification for each of the changes, including references to lessons learned.

N/A.

A list of planned future improvements and/or updates to the activity, including a timeline for implementation.

N/A.

As applicable, a discussion of the status of any undergrounding work plans and progress, as required by Public Utilities Code section 8388.5(f)(2).

N/A.

As applicable, a discussion of any evaluations related to scoping grid hardening projects to account for future grid needs (e.g., load capacity, peak demand, system flexibility).

N/A.

Compatible initiatives: N/A

8.3 Asset Inspections

In this section, the electrical corporation must provide an overview of its procedures for inspecting its assets.

The electrical corporation must first summarize details regarding its asset inspections in Table 8-2. The table must include the following:

- ***Type of inspection**: i.e., distribution, transmission, or substation.*
- ***Inspection activity (program) name:** Identify various inspection activity (program)s within the electrical corporation.*
- ***Frequency or trigger**: Identify the frequency or triggers, such as inputs from the risk model. Indicate differences in frequency or trigger by HTFD Tier, if applicable.*
- ***Method of inspection**: Identify the methods used to perform the inspection (e.g., patrol, detailed, aerial, climbing, and LiDAR).*
- ***Governing standards and operating procedures**: Identify the initiative construction standards and the electrical corporation's procedures for addressing them, and other internal protocols for work described.*
- ***Quarterly targets:** Provide the cumulative quarterly targets for each year of the WMP cycle.*
- ***% of HFRA and HFTD covered annually by inspection type:** Determine the percentage of either circuit mileage or number of assets covered annually by the inspection type within the HFRA and HFTD.*
- ***Find rate**: Identify the find rate of level 1, 2, and 3 conditions over the three calendar years prior to the Base WMP submission. The find rate must be expressed as the percentage of inspections resulting in findings and identify the inspection unit.*
- ***Clarifying information:** Provide electrical corporation-specific risk informed triggers used for asset inspections and electrical corporation-specific definitions of the different methods of inspection.*

Table 8-2: Asset Inspection Frequency, Method, and Criteria

Type	Inspection Activity Program	Frequency or Trigger (Note 1)	Method of Inspection (Note 2)	Governing Standards & Operating Procedures	Cumulative Quarterly Target 2026, Q1	Cumulative Quarterly Target 2026, Q2	Cumulative Quarterly Target 2026, Q3	Cumulative Quarterly Target 2026, Q4	Cumulative Quarterly Target 2027, Q1	Cumulative Quarterly Target 2027, Q2	Cumulative Quarterly Target 2027, Q3	Cumulative Quarterly Target 2027, Q4	Cumulative Quarterly Target 2028 Q1	Cumulative Quarterly Target 2028, Q2	Cumulative Quarterly Target 2028, Q3	Cumulative Quarterly Target 2028, Q4	% of HFRA and HFTD Covered Annually by Inspection Type [1]	Condition Find Rate Level 1[2]	Condition Find Rate Level 2[3]	Condition Find Rate Level 3
Distribution	Distribution High Fire Risk-Informed (HFRI) Inspections - Ground and Aerial (IN-1.1)	As Identified in Section 8.3.1.2	Detailed[118] Ground Inspection and Detailed Aerial Inspection	GO95 GO 165 Distribution Inspection Maintenance Program (DIMP)	41,200	103,000	175,100	206,000	41,200	103,000	175,100	206,000	41,200	103,000	175,100	206,000	approximately 72%	0.1%	32.5%	17.3%
Transmission	Transmission High Fire Risk-Informed (HFRI) Inspections - Ground and Aerial (IN-1.2)	As Identified in Section 8.3.2.2	Detailed Ground Inspection and Detailed Aerial Inspection	GO95 GO 165 Transmission Inspection Maintenance Program (TIMP) Manual	5,540	13,850	23,545	27,700	5,540	13,850	23,545	27,700	5,540	13,850	23,545	27,700	approximately 77%	0.2%	5.5%	11.3%
Distribution	Distribution Infrared Inspections (IN-3)	As identified in Section 8.3.3.2	Infrared (see Section 8.3.3.1)	GO 95 GO 165	0	2,500	5,200	5,300	0	2,500	5,200	5,300	0	2,500	5,200	5,300	Approximately 58%	0.2%	1.47%	N/A[119]
Transmission	Transmission Infrared and Corona Scan Inspections (IN-4)	As identified in Section 8.3.4	Infrared and Corona Scan (see Section 8.3.4)	GO 95 GO 165	100	550	900	1,000	100	550	900	1,000	100	550	900	1,000	Approximately 25%	N/A[120]	0.12%	0.43%
Generation	Generation HFRI Inspections (IN-5)	As identified in Section 8.3.5.2	Detailed Ground Inspections (see Section 8.3.5.1)	GO 95 GO 167-B	0	45	160	160	0	55	170	170	0	50	160	160	approximately 62%	N/A[121]	3%	15%

1 Distribution and Transmission Infrared Inspections are based on circuit miles in HFRA.
2 The Level 1, 2 & 3 find rate for Distribution, Transmission and Generation HFRI Inspections are based on the number of findings in each category (P1, P2, P3) divided by the total number of assets inspected by each program. For Distribution and Transmission. Infrared Inspections, the find rate is based on the number of findings in each category (P1, P2, P3) divided by the total number of circuit miles inspected by each program.
3 This includes non-SCE issues such as conditions that require actions from customers or Communication Infrastructure Providers (CIP).

118 As referenced within GO165, Section III-A4.
119 No P3 findings were identified for Distribution Infrared Inspections from 2022-2024.
120 No P1 findings were identified for Transmission Infrared Inspections from 2022-2024.
121 No P1 findings were identified for Generation HFRI Inspections from 2022-2024.

The electrical corporation must then provide a narrative overview of each asset inspection activity (program) identified in the above table; Section 8.3.1. provides instructions for the overviews. The sections should be numbered Section 8.3.1 to Section 8.3.n (i.e., each asset inspection activity [program] is detailed in its own section). The electrical corporation must include inspection activity (programs) it is discontinuing or has discontinued since the last WMP submission; in these cases, the electrical corporation must explain why the activity (program) is being discontinued or has been discontinued. The electrical corporation must also include inspection activities (programs) being piloted; for pilot inspection activities (programs), the electrical corporations must include a discussion of how it measures the effectiveness of the pilot and how it determines next steps for the pilot (e.g. to expand, discontinue, or move to permanent activity [program]).

8.3.1 Distribution High Fire Risk-Informed (HFRI) Inspections - Ground and Aerial (IN-1.1)

8.3.1.1 Overview

In this section, the electrical corporation must provide an overview of the individual asset inspection activity (program), including inspection criteria and the various inspection methods used for each inspection activity (program).

SCE performs visual detailed inspections of distribution facilities as part of its routine practices throughout its service territory in compliance with GO 165. Degradation of equipment and structures as part of wear and tear during normal operations and due to external factors, such as weather or third-party caused damage, increases the probability of in-service malfunction or failures that can have safety and service reliability impacts. GO 95 provides guidance on overhead electric line construction standards and GO 165 provides guidance on the maximum intervals for inspections. SCE performs inspections in HFRA that go beyond the GO 95 and GO 165 requirements as described below.

To identify equipment or structure degradation that occurs between compliance cycles that could lead to a potential ignition risk, SCE conducts more frequent and ignition-focused risk inspections in HFRA beyond GO 165 requirements ("High Fire Risk-Informed inspections" or "HFRI inspections"). For an example of an inspection finding, see the cracked Hendrix insulator shown below in Figure SCE 8-12.

Since 2019, SCE has performed aerial detailed visual inspections via helicopter or drone (as shown below in Figure SCE 8-13) in HFRA to supplement ground-based inspections. SCE also conducts ground inspections because they may detect conditions difficult to identify via aerial inspections, such as the state of guy anchors or damaged structures like wood poles and guy stub poles (see Figure SCE 8-15 and Figure SCE 8-14 below).

In 2023, SCE began conducting single-visit 360 inspections for distribution assets (33kV and below), combining ground and aerial checks. This process usually involves both an inspector and a pilot, but sometimes one inspector can perform both. By 2024, most distribution inspections used the 360 method, with exceptions where only ground or aerial inspections were feasible due to terrain or other constraints. SCE plans to continue 360 HFRI inspections from 2025 onward.

Figure SCE 8-12: Cracked Hendrix Insulator (Drone Capture)

Distant	At Close Range
	

Figure SCE 8-13: Drone (left) and SCE Helicopter (right)

Distribution Aerial Inspection (Drone)	SCE Helicopter
	

Figure SCE 8-14: Damaged Pole Carrying 120V

Distant	At Close Range
	

Figure SCE 8-15: Rotten / Hollow Guy Stub Pole

Distant	At Close Range
	

The frequency of HFRI inspections varies by the location-specific risk (as defined by IWMS) within SCE's HFRA, structure-specific risk (as defined by the structures Probability of Ignition and Wildfire Consequence), and emergent conditions. Issues identified by inspectors during detailed inspections are prioritized for remediation to be completed within GO 95 compliance timelines. Remediations can be repairs to or replacements of existing assets depending on asset condition.

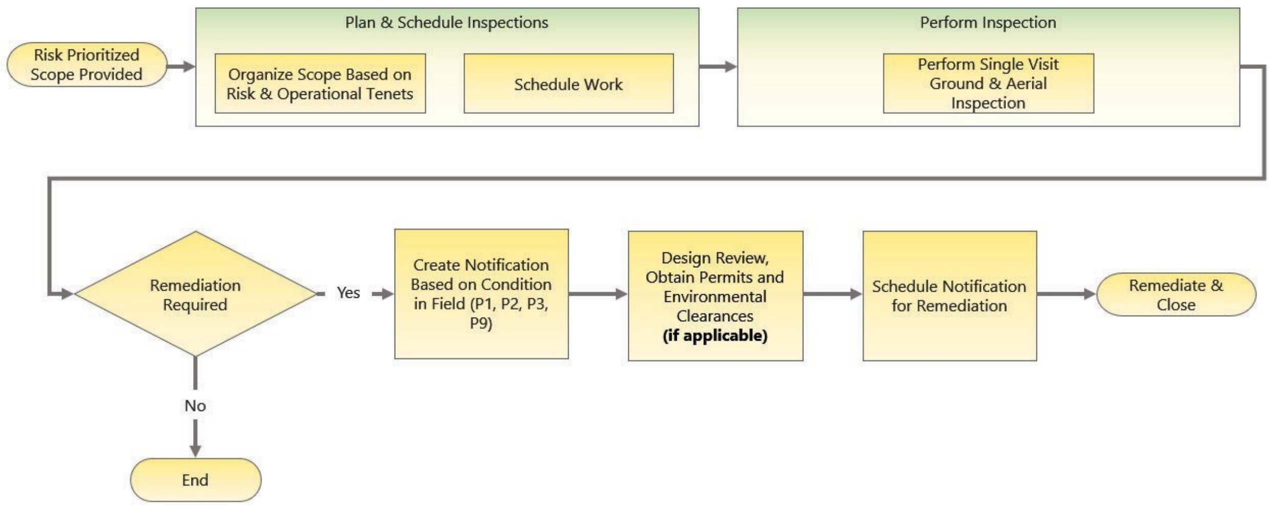
One way in which SCE has enhanced its HFRI inspections is by identifying Areas of Concern (AOCs) in HFRA, which are areas that pose increased risk due to fuel-driven and wind-driven fire conditions. These AOCs are identified annually based on factors such as fire history, current and near-term weather conditions, fuel type, wind exposure, and egress. To mitigate potential risks in AOCs, SCE implements an action plan that includes inspections of assets (e.g., distribution, transmission, and generation) and accelerates remediation for the highest-risk assets.

SCE's Distribution HFRI activity targets are provided in Table 8-1. If factors outside of SCE's control facilitate execution of additional units, SCE will strive to inspect up to 221,000 structures annually in SCE's HFRA. This level of execution depends on exogenous factors like the issuance of permits and environmental clearances.

Include relevant visuals and graphics depicting the workflow and decision-making process the electrical corporation uses for the inspection activity (program).

Figure 8-1a below depicts the workflow and decision process regarding distribution detailed inspections.

Figure 8-1a: Distribution Detailed Inspections and Remediations Workflow



8.3.1.2 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 activity (program), such as inputs from the risk model.

SCE conducts detailed inspections of each structure within HFRA at least once every three years, which exceeds the GO 165 requirements of once every five years.[122] Standard ground-based distribution detailed inspections continue to be performed in SCE's non-HFRA every five years in accordance with GO 165 requirements.

Because risk levels vary across SCE's HFRA, structures are prioritized for inspection based on Probability of Ignition (POI) and consequence. In determining the Distribution HFRI inspection scope, SCE used the locational risk categorization from its IWMS Risk Framework, incorporated the latest risk modeling, and appropriate reserve capacity needed for resources to perform AOC-based inspections. SCE applies the following methodology for determining the Distribution HFRI inspection scope:

- SCE will annually inspect all structures in areas identified as Severe Risk Areas and those structures identified within an AOC.
- Additionally, SCE may inspect a portion of the highest risk structures in the Severe Risk Areas IWMS category as frequently as twice per year.
- Structures in High Consequence Areas will either be inspected annually, or up to once every three years depending on the risk profile.
- All remaining lower risk structures captured within the IWMS Other HFRA category will be inspected once every three years.

If the inspection activity (program) is schedule-based, the electrical corporation must explain how it uses risk prioritization in the scheduling of the inspection activity (program) to target high-risk

122 The not to exceed three-year frequency guidance applies to all structures within HFRA distribution scope (e.g., distribution poles, combination poles and streetlight only poles).

areas. If the electrical corporation does not use risk prioritization in the scheduling of the inspection activity (program), it must explain why.

SCE uses a risk-informed strategy as described above to identify inspection scope and largely schedules those inspections in HFRA to be performed before the peak of fire season. Non-HFRA inspections are scheduled to be completed based on their compliance due dates. Additionally, SCE aligns its inspections scheduling with the needs of Summer AOCs and Fall AOCs.

8.3.1.3 Accomplishments, Roadblocks, and Updates

In this section, the electrical corporation must discuss:

- *How the electrical corporation measures success for the inspection activity (program) (excluding routine inspections.)*

In 2024, SCE completed approximately 208,800 distribution ground inspections and approximately 206,900 distribution aerial inspections, which exceeded the targets of 187,000 ground and aerial distribution HFRI inspections. SCE's HFRI inspections exceed compliance requirements that require asset inspection every five years. SCE also performed inspection of distribution and transmission combo poles in a single visit by a Senior Electrical System Inspector, reducing customer impacts from site visits.

- *Roadblocks the electrical corporation has encountered while implementing the inspection activity (program) and how the electrical corporation has addressed the roadblocks.*

The primary roadblock encountered for certain Distribution HFRI inspections was access issues, such as those due to difficult terrain or lack of access to customer premises. Under limited circumstances, SCE may use aerial footage or high-quality photos to complete ground inspections when SCE cannot access an inspection site on the ground due to conditions such as hazardous terrain or other natural or man-made obstructions. In those cases, a qualified inspector may review aerial images or footage of a structure to complete ground inspection survey questions. Moreover, when possible, inspection schedules were streamlined for customers who were affected more often to reduce the number of visits.

For overhead detailed inspections, there will also be certain circumstances when a full detailed inspection may not be possible because SCE cannot access an inspection site due to hazardous terrain or other environmental conditions. In those instances, SCE may use aerial footage to complete a "limited inspection." A limited inspection occurs when a full detailed inspection of the critical distribution assets of a structure can be safely taken, but hazardous terrain or environmental conditions prevent the inspector from viewing the entirety of the distribution equipment even with the use of a drone.

- *Changes/updates to the inspection activity (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 five years, including references to and strategies from pilot projects and research.*

SCE's distribution inspection survey questionnaire was updated in 2024 to include additional criteria for identifying issues such as covered conductor corrosion, surface damage, and water intrusion.

In 2026-2028, SCE will explore transitioning to circuit segment-based scoping of inspections rather than structure-based inspections scoping. This transition can help improve the efficiency of completing inspections in the field. Additionally, by grouping structures into circuit-segments, customer impact could be reduced in instances where customers have multiple structures near or on their property. The circuit-segment based scoping may also help by giving inspectors the ability to identify newly installed structures during their visit and by doing so ensure field and system data alignment.

In 2026-2028, SCE will include detailed inspections of telecommunication equipment on distribution poles as part of its HFRI distribution inspections. These inspections are currently performed across SCE's service territory through SCE's overhead detailed inspection program. By bundling telecom inspections with HFRI distribution activities, SCE aims to improve operational efficiency and minimize repeat visits to the same location within inspection cycles.

The electrical corporation must also include inspection activities (programs) being piloted; for pilot inspection activities (programs), the electrical corporations must include a discussion of how it measures the effectiveness of the pilot and how it determines next steps for the pilot (e.g. to expand, discontinue, or move to permanent activity [program]).

SCE is piloting the use of artificial intelligence (AI)/machine learning (ML) models for (1) object detection, which involves answering inspection survey questions to identify equipment attributes, and (2) condition detection, which involves using AI models to supplement the identification of conditions which enables a quality review of inspection findings. The object detection models have several use cases, such as identifying unauthorized attachments and answering survey questions, which can potentially reduce the size of the survey performed by the inspector and expedite the process of performing inspections in the field. In 2025 and beyond, SCE plans to enhance the object detection model to identify unauthorized attachments.

SCE's pilot for condition detection uses AI models for asset issue recognition. These AI models serve as an additional quality control measure, aiding in the identification of potential issues from HFRI inspections, considering the extensive detail required from both ground and aerial inspections. The models analyze images to identify possible findings, which are then reviewed by human experts. The identified potential issues are used to provide feedback to inspectors and, in some cases, can generate notifications. Presently, there are approximately nine different models (that detect specific types of issues) operating across various types of equipment. SCE currently is developing more use cases for distribution and transmission condition detection in 2025.

In 2026-2028, SCE will assess the feasibility of automating the notification process based on the issues detected by these models. The success of this pilot program will be evaluated based on the accuracy with which the AI models identify issues that can inform relevant asset remediation actions.

In 2025, SCE is exploring the application of Light Detection and Ranging (LiDAR) technology to enhance asset inspections. The application of LiDAR data and other technologies such as computer vision models can help validate asset locations and assess equipment on utility poles, identifying discrepancies in asset records and prompting targeted field inspections for validation and updates.

LiDAR's high-resolution imaging capabilities allow for the completion of specific asset inspections survey questions using data obtained from images. LiDAR can also facilitate the assessment of asset clearance with greater accuracy, reducing the variability inherent in manual inspection methods. Examples of asset clearances include conductor-to-conductor spacing, clearances between guy wires and energized conductors.

In 2026-2028, SCE will have a better understanding of cost and requirements to deploy LiDAR effectively as part of its asset inspection strategy. SCE's adoption of LiDAR technology represents a forward-looking approach. By leveraging remote sensing and imaging techniques, SCE aims to enhance the reliability and safety of its electrical distribution and transmission systems.

8.3.2 Transmission High Fire Risk-Informed (HFRI) Inspections - Ground and Aerial (IN-1.2)

8.3.2.1 Overview

In this section, the electrical corporation must provide an overview of the individual asset inspection activity (program), including inspection criteria and the various inspection methods used for each inspection activity (program).

SCE performs detailed inspections of SCE's overhead transmission electric system in compliance with regulatory requirements including GO 165, NERC and WECC rules and regulations, and the CAISO Transmission Control Agreement.

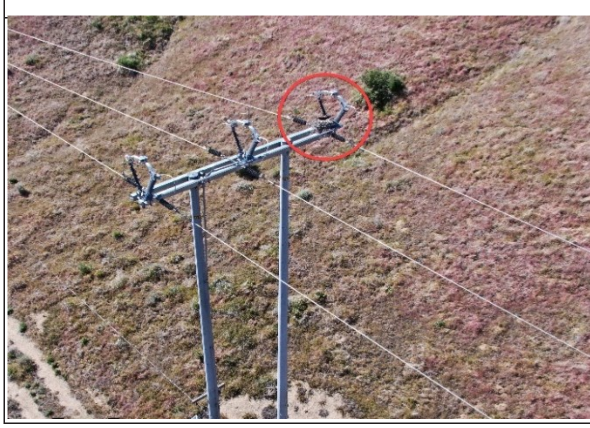
To identify transmission equipment or structure degradation that occurs between compliance cycles due to natural wear and tear or emergent events such as weather or third-party caused damages that could lead to a potential ignition risk, SCE has implemented more frequent and ignition-focused HFRI on transmission equipment and structures in HFRA.

As with distribution inspections, aerial inspections supplement ground-based inspections. Aerial inspections are typically performed at the same locations as ground inspections and in combination provide a 360-degree view to detect equipment/structure conditions that can be difficult to identify via ground inspections.

SCE conducts the 360-degree view detailed inspection for its structures in HFRA regardless of scope driver (i.e. risk or compliance).

For an example of a 360-inspection, see Figure SCE 8-16.

Figure SCE 8-16: Animal Nest Found on Transmission Switchgear (Drone Capture)

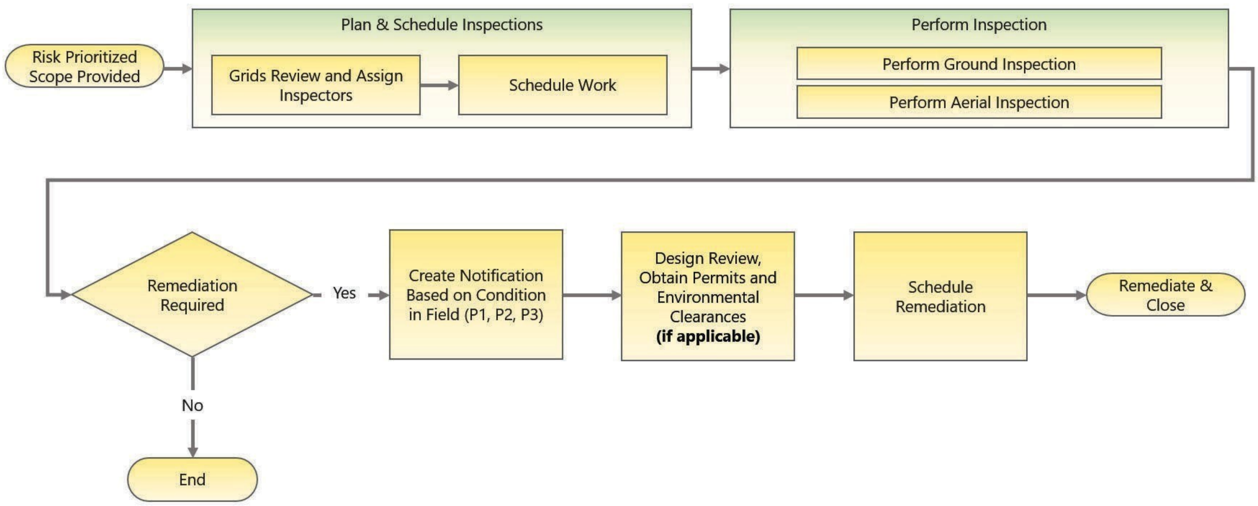
Distant	At Close Range
	

SCE's Transmission HFRI activity targets are provided in Table 8-1. If factors outside of SCE's control facilitate execution of additional units, SCE will strive to inspect up to 28,500 structures annually in SCE's HFRA. This level of execution depends on exogenous factors like the issuance of permits and environmental clearances.

Include relevant visuals and graphics depicting the workflow and decision-making process the electrical corporation uses for the inspection activity (program).

Figure 8-2 depicts the workflow and decision process regarding transmission detailed inspections.

Figure 8-2: Transmission Detailed Inspections Workflow



8.3.2.2 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 activity (program), such as inputs from the risk model.

SCE performs a detailed transmission inspection of its entire service territory over the span of three years. As risk levels vary across SCE's HFRA, a targeted quantitative approach for transmission inspections is used to balance risk reduction, resource availability, and costs. Structures are prioritized for inspection based on POI and consequence. SCE aligned its inspection scope with the IWMS while taking into account the resource requirements of potential emergent inspections throughout the year.

Transmission structures in Severe Risk Areas and those structures identified within an AOC will be inspected annually at a minimum, and a portion of highest risk structures in the Severe Risk Areas may be inspected twice a year. Additionally, transmission structures in High Consequence Areas will either be inspected annually, or up to once every three years. Remaining lower risk transmission structures in the IWMS Other HFRA category will be inspected once every three years.

If a compliance inspection in HFRA is scheduled to be performed around the same time as an HFRI inspection, the inspection requirements are combined into one inspection. The transmission HFRI inspections and remediations frequency methodology is similar to distribution as described in Section 8.3.1.2 above.

If the inspection activity (program) is schedule-based, the electrical corporation must explain how it uses risk prioritization in the scheduling of the inspection activity (program) to target *high-risk areas. If the electrical corporation does not use risk prioritization in the scheduling of the inspection activity (program), it must explain why.*

SCE uses a risk-informed strategy as described above to identify inspection scope and then schedules those inspections in HFRA to be performed before the peak of fire season. Additionally, SCE prioritizes inspections in Summer AOC areas to be completed for summer readiness, and Fall AOC areas to be completed for Fall readiness.

8.3.2.3 Accomplishments, Roadblocks, and Updates

- *In this section, the electrical corporation must discuss: How the electrical corporation measures success for the inspection activity (program) (excluding routine inspections).*

In 2024, SCE completed approximately 31,700 transmission ground inspections and approximately 30,700 transmission aerial inspections, which exceeded the targets of 28,000 ground and aerial transmission HFRI inspections. SCE's HFRI inspections go above the compliance requirements that require asset inspection every three years. SCE also performed inspection of distribution and transmission combo poles in a single visit, reducing customer impacts from site visits.

- *Roadblocks the electrical corporation has encountered while implementing the inspection activity (program) and how the electrical corporation has addressed the roadblocks.*

SCE experienced certain access and environmental issues while conducting HFRI transmission inspections, which are addressed in SCE's ACI response in Appendix D (SCE-25U-06). Under limited circumstances, SCE may use aerial footage or high-quality photos to complete ground inspections when SCE cannot access an inspection site on the ground due to conditions such as hazardous terrain or other natural or man-made obstructions. In those cases, a qualified inspector may review aerial images or footage of a structure to complete ground inspection survey questions.

- *Changes/updates to the inspection activity (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, including references to and strategies from pilot projects and research.*

As mentioned in section 8.3.1.3, SCE is piloting the use of AI/ML models for both distribution and transmission assets. SCE will further expand the transmission use cases in 2025.

In 2026-2028, SCE will also incorporate detailed inspections of telecommunication equipment on transmission poles and towers into its HFRI transmission inspections. This approach mirrors the bundling strategy to be used in distribution HFRI inspections, with the goal of streamlining operations and reducing repeat site visits during inspection cycles.

8.3.3 Distribution Infrared Scanning (IN-3)

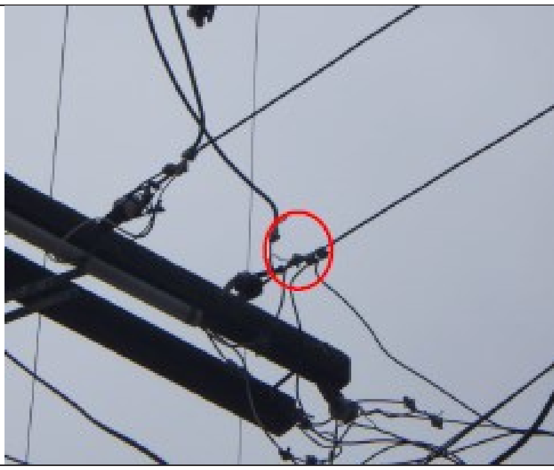
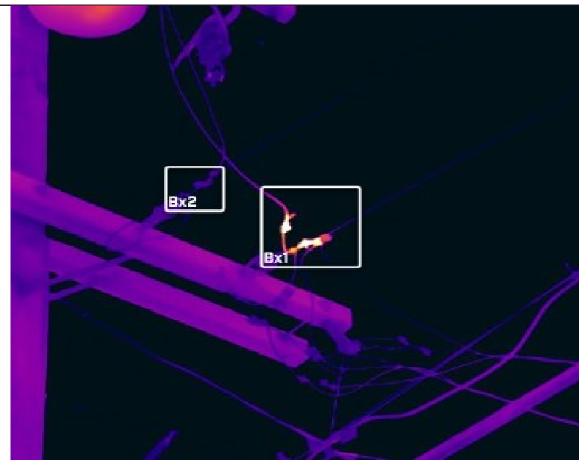
8.3.3.1 Overview

In this section, the electrical corporation must provide an overview of the individual asset inspection activity (program), including inspection criteria and the various inspection methods used for each inspection activity (program).

Infrared (IR) scanning inspections offer a substantial benefit beyond standard visual inspection, as they can detect temperature differences between components and identify heat signatures of components called “hot spots” that may indicate deterioration in structures and equipment not visible to the naked eye. IR inspections can detect conditions that may indicate a wide range of anomalies, including, but not limited to, failing switch and fuse contacts, poor connections, loose bushings, and overloaded/failing transformers.

Most inspections are performed from ground vehicles; however, a small percentage of the inspections require the inspector to hike to the structure or perform the inspection from a helicopter.

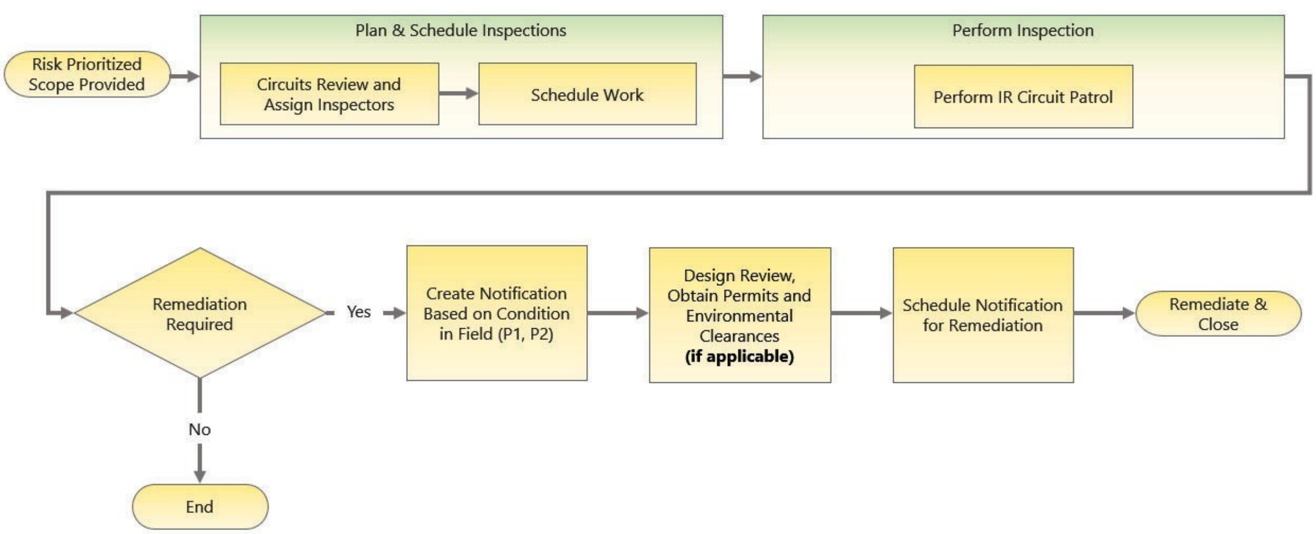
Figure SCE 8-17: Distribution Infrared (IR) Inspection of a 12kV Circuit

Standard Imagery	Thermal Imagery
	

Include relevant visuals and graphics depicting the workflow and decision-making process the electrical corporation uses for the inspection activity (program).

Figure 8-3 depicts the workflow and decision process regarding distribution infrared (IR) inspections.

Figure 8-3: Distribution Infrared Inspections Workflow



8.3.3.2 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 activity (program), such as inputs from the risk model.

SCE will continue to perform IR scans on overhead distribution equipment throughout SCE's territory within HFRA from 2026 through 2028. Districts are risk assessed by their probability of ignition and consequence levels and then prioritized by their calculated risk score. The districts selected to be inspected annually were not only the highest risk but also had large portions of their circuits that were within High Consequence Areas and Severe Risk Areas.

If the inspection activity (program) is schedule-based, the electrical corporation must explain how it uses risk prioritization in the scheduling of the inspection activity (program) to target high-risk areas. If the electrical corporation does not use risk prioritization in the scheduling of the inspection activity (program), it must explain why.

SCE inspects the highest risk districts annually with the remaining scope being split evenly and inspected every two years. The inspections are optimized and scheduled where possible around the summer months to best recognize peak loading and temperatures of SCE's equipment.

8.3.3.3 Accomplishments, Roadblocks, and Updates

- *In this section, the electrical corporation must discuss: How the electrical corporation measures success for the inspection activity (program) (excluding routine inspections).*

In 2024, SCE completed infrared inspection on approximately 5,400 distribution circuit miles, which exceeded the target of 5,300 circuit miles.

- *Roadblocks the electrical corporation has encountered while implementing the inspection activity (program) and how the electrical corporation has addressed the roadblocks.*

SCE did not experience notable roadblocks in implementing this inspection activity (program) in 2024.

- *Changes/updates to the inspection activity (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, including references to and strategies from pilot projects and research.*

SCE is exploring the potential of sharing contractor resources between distribution and transmission for infrared inspections (where feasible) to optimize the execution of infrared inspections and enhance operational efficiency. From 2026 to 2028, SCE will determine the feasibility of sharing contractor resources between both programs.

In 2026-2028, similar to Distribution HFRI inspections, SCE will explore transitioning to circuit segment-based scoping of infrared scanning rather than district-based inspections scoping.

8.3.4 Transmission Infrared (IR) and Corona Scanning (IN-4)

8.3.4.1 Overview

In this section, the electrical corporation must provide an overview of the individual asset inspection activity (program), including inspection criteria and the various inspection methods used for each inspection activity (program).

Similar to Distribution IR scanning, Transmission IR and corona scanning offer a substantial benefit beyond standard visual inspections, as they can detect anomalies within structures and equipment not visible to the naked eye. Particular attention is paid to splices, conductor connection/attachment points, and insulators.

Similar to the distribution IR scanning protocol, the infrared scan detects temperature differences and heat signatures of components, which may indicate problems that could result in component/conductor failure. Corona scanning is an additional technology that is used on transmission circuits in HFRA to detect certain anomalies (e.g., insulator failures) that are not as common on distribution circuits.

Corona detection is accomplished by identifying ultraviolet energy, which is generated by electric discharge or "leakage" due to the ionization of air surrounding high voltage electric components. In some cases, the "leakage" is substantial enough that it may result in an arc flash and potential ignition.

Figure SCE 8-18 below shows an example of a defect that was captured by an Infrared scan that could not be detected during a visual or Corona inspection. Helicopters (see Figure SCE 8-19 below) are used for these inspections due to the long distances between structures and because these assets are frequently located on rugged terrain.

See Figure SCE 8-18 for an example of standard and infrared imagery.

Figure SCE 8-18: Control-Haiwee-Inyokern 115kV line

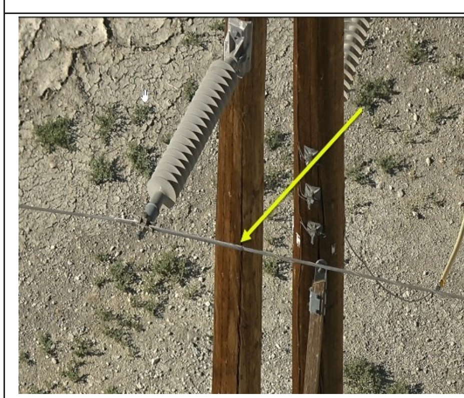
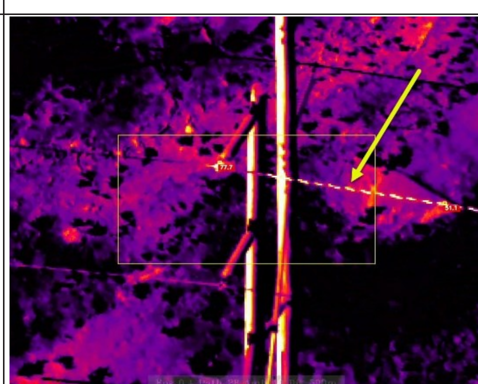
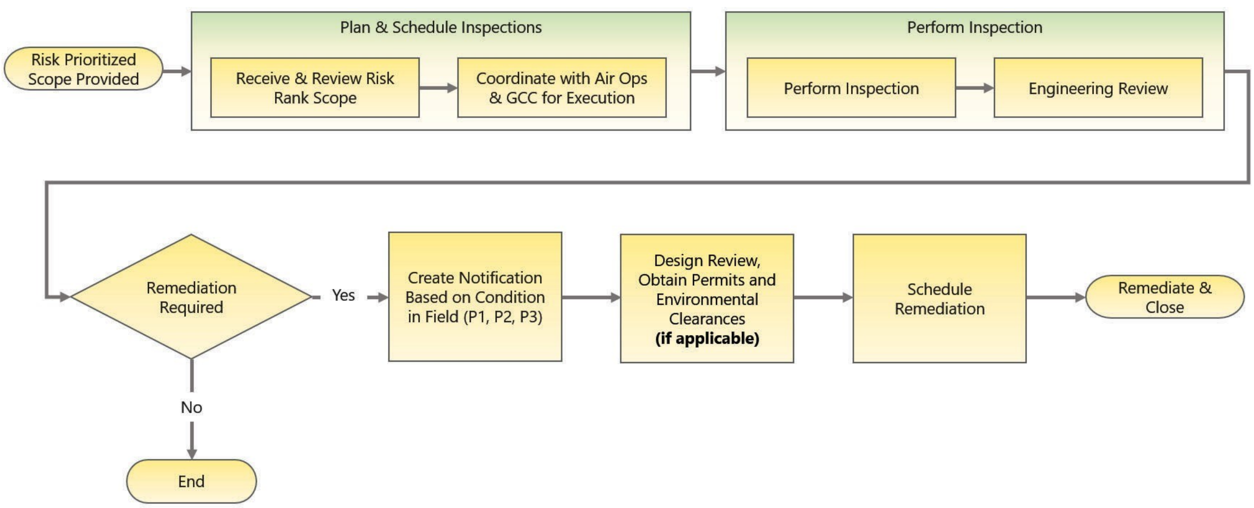
Visual	Infrared	Corona Scan
		

Figure SCE 8-19: SCE Helicopters

SCE Helicopter	Mounted with IR & Corona Camera
	

Include relevant visuals and graphics depicting the workflow and decision-making process the electrical corporation uses for the inspection activity (program).

Figure 8-4: TRANSMISSION INFRARED AND CORONA SCAN INSPECTIONS WORKFLOW



8.3.4.2 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 activity (program), such as inputs from the risk model.

SCE inspects the highest risk circuits annually with the remaining scope on a five-year review cadence, which distributes the risk proportionally each year. The work is executed in an operationally efficient manner, considering weather conditions, circuit loading, outages, and the proximity of other circuits. The inspections are optimized and scheduled where possible around the summer months to best recognize peak loading and temperatures of SCE's equipment.

If the inspection activity (program) is schedule-based, the electrical corporation must explain how it uses risk prioritization in the scheduling of the inspection activity (program) to target high-risk areas. If the electrical corporation does not use risk prioritization in the scheduling of the inspection activity (program), it must explain why.

Circuits are risk assessed by their probability of ignition and consequence levels and then prioritized by their calculated risk score. The circuits inspected in the previous year are removed from the priority list unless identified as one of the highest risk circuits using POI and Technosylva FireSight 8.0 consequence.

8.3.4.3 Accomplishments, Roadblocks, and Updates

- *In this section, the electrical corporation must discuss: How the electrical corporation measures success for the inspection activity (program) (excluding routine inspections).*

In 2024, SCE completed infrared inspection on approximately 1,090 transmission circuit miles, which exceeded the target of 1,000 circuit miles.

- *Roadblocks the electrical corporation has encountered while implementing the inspection activity (program) and how the electrical corporation has addressed the roadblocks.*

SCE did not experience any notable roadblocks in implementing this inspection activity (program) in 2024.

- *Changes/updates to the inspection activity (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, including references to and strategies from pilot projects and research.*

Starting in 2025 and continuing from 2026-2028, SCE will explore options to expand data storage capacity for storing, sharing and maintaining the increasing volume of large video files generated from this program.

8.3.5 Generation HFRI Inspections (IN-5)

8.3.5.1 Overview

In this section, the electrical corporation must provide an overview of the individual asset inspection activity (program), including inspection criteria and the various inspection methods used for each inspection activity (program).

SCE's Generation HFRI program inspects generation-related assets in HFRA including powerhouses, substations, and low-voltage ancillary assets to identify needed remediations to reduce the risk of wildfire ignition. These inspections include ignition-focused assessments of low-voltage ancillary assets and their associated overhead lines, supporting structures, and any exposed wiring and/or threats from vegetation that require additional mitigation.

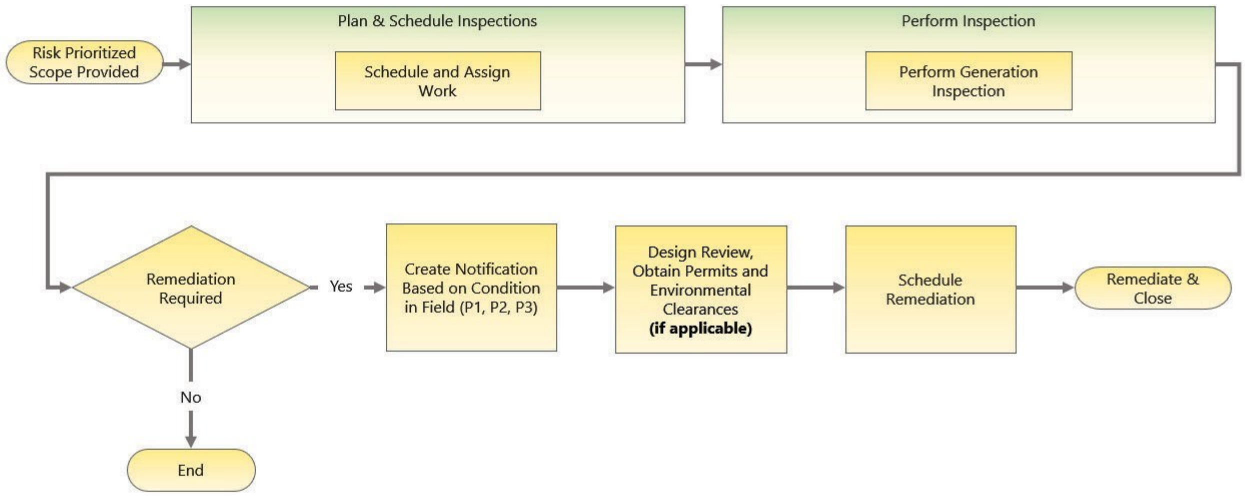
SCE's generation facilities in HFRA are often located in or near heavily forested areas, and ignitions related to these facilities could lead to substantial wildfire risk. Once asset deterioration or other corrective actions are identified during inspections, remediations of these conditions are intended to reduce the probability of faults and potential ignitions. The program streamlines field efforts by integrating wildfire-related inspections into existing routine equipment and operations inspections.

SCE's Generation HFRI activity targets are provided in Table 8-1. If factors outside of SCE's control facilitate execution of additional units, SCE will strive to inspect 190 generation related assets annually in SCE's HFRA, subject to resource constraints and other execution risks. This level of execution depends on exogenous factors like the issuance of permits and environmental clearances.

Include relevant visuals and graphics depicting the workflow and decision-making process the electrical corporation uses for the inspection activity (program).

Figure 8-6 depicts the workflow and decision process regarding generation inspections.

Figure 8-5: Generation Inspections Workflow



8.3.5.2 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 activity (program), such as inputs from the risk model.

If the inspection activity (program) is schedule-based, the electrical corporation must explain how it uses risk prioritization in the scheduling of the inspection activity (program) to target high-risk areas. If the electrical corporation does not use risk prioritization in the scheduling of the inspection activity (program), it must explain why.

The frequency of generation HFRI inspections is based on each asset's calculated risk, based on POI and Technosylva consequence. SCE inspects the generation assets that pose 75% of the highest risk on an annual cadence. The assets that pose the lowest 25% are lower risk and are divided equally over a two-year cycle. This allows SCE to inspect approximately 88% of the risk associated with these facilities on a yearly basis.

Generation inspections are scheduled to be executed in an operationally efficient manner, which consider weather conditions and geographical location and are completed before peak fire season.

8.3.5.3 Accomplishments, Roadblocks, and Updates

In this section, the electrical corporation must discuss:

- *How the electrical corporation measures success for the inspection activity (program) (excluding routine inspections).*

In 2024, SCE completed inspections on 225 generation-related assets in HFRA, which exceeded the target of 160 generation related assets.

- *Roadblocks the electrical corporation has encountered while implementing the inspection activity (program) and how the electrical corporation has addressed the roadblocks.*

In 2024, SCE identified additional AOC HFRI inspections for generation, leading to an accelerated schedule compared to prior years. SCE completed inspections and associated remediations before the end of the summer and fall AOC periods. For generation, maintenance outages are typically planned during periods of low electricity demand to minimize operational disruptions. However, in 2024, the expanded scope and accelerated timeline overlapped with the time and resources usually allocated for maintenance tasks, creating constraints. To address the additional scope while meeting deadlines, SCE applied extra coordination criteria for outage planning, balancing wildfire inspections and maintenance with non-wildfire tasks. Through these coordination efforts, SCE worked to optimize scheduling and resource allocation to achieve the company's wildfire mitigation objectives.

- *Changes/updates to the inspection activity (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, including references to and strategies from pilot projects and research.*

In 2025, SCE will explore transitioning to a different inspection application or integrating a digital tool into the existing Survey123 application for performing generation HFRI inspections, with the objective of automating the creation of notifications when an issue is identified during field inspections in preparation for 2026-2028 scope.

SCE is going through a divestment process for some small hydro generation facilities. Pending the completion of the process and regulatory approvals, SCE would adjust program scope to no longer inspect assets that have been transferred to a new owner.

8.3.6 (Discontinued) Transmission Conductor and Splice Assessment

The electrical corporation must include inspection activities (programs) it is discontinuing or has discontinued since the last WMP submission; in these cases, the electrical corporation must explain why the activity (program) is being discontinued or has been discontinued.

The Transmission Conductor and Splice Assessment (IN-9), which included X-ray and LineVue inspections, had a relatively high find rate for X-ray inspections from 2022 to 2024. Based on lessons learned, SCE will no longer continue this assessment. Instead, SCE will initiate a proactive splice shunting program (SH-20), starting with a pilot in 2025 and a WMP target in 2026.

The new splice shunting program foregoes the pre-remediation inspections in favor of more streamlined remediations, reducing remediation timelines and costs. This approach uses lessons learned and risk-informed prioritization to address potential splice issues. Please refer to Section 8.2.6.4 for more details on this initiative.

8.4 Equipment Maintenance and Repair

In this section, in addition to the information described above regarding distribution, transmission, and substation inspections, the electrical corporation must provide a brief narrative of maintenance activity (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:

1. *Capacitors*
2. *Circuit breakers*
3. *Connectors, including hotline clamps*
4. *Conductor, including covered conductor*
5. *Fuses including expulsion fuses*
6. *Distribution Pole*
7. *Lightning arrestors*
8. *Reclosers*
9. *Splices*
10. *Transmission poles/towers*
11. *Transformers*
12. *Non-exempt equipment*
13. *Pre-GO 95 legacy equipment*
14. *Other equipment not listed*

For equipment types 12 – 14 above, the electrical corporation must include sub-categories for each relevant equipment type. For each equipment type, the electrical corporation must include sections for the following information:

- ***Condition monitoring:*** *a description of how the electrical corporation monitors the condition of the equipment (e.g., human visual inspection, automated visual inspection, human sensor readings, automated sensor readings).*
- ***Maintenance strategy:*** *identification and brief description of the maintenance strategy (e.g. reactive, preventative, predictive, reliability-centered).*
- ***Replacement/repair condition:*** *a description of how equipment is identified for repair or replacement (e.g., time interval, inspection finding, sensor reading, predictive maintenance, data analytics, machine learning).*
- ***Timeframe for remediation:*** *a list of possible conditions and findings, including the priority level and associated timeframes for remediation of each.*

- ***Failure rate:*** *the number of total failures attributed to the given equipment type in the HFTD and HFR[123]A during the three calendar years prior to the base WMP submission, broken out by distribution, transmission, and substation. The failure rate must include the likelihood of failure based on the ratio of number of failures to the number of total assets in-field within the HFTD/HFRA for the equipment type.*

- ***Ignition rate:*** *the total number of CPUC-reportable ignitions attributed to the equipment type in the HFTD and HFRA during the ten calendar years prior to the base WMP submission, broken out by distribution, transmission, and substation. The ignition rate must include evaluation of the likelihood that an equipment failure will propagate into an ignition based on the ratio of the number of failures to the number of ignitions attributed to the equipment type.*

123 Equipment that falls in both the HFTD and HFRA should not be counted twice. The number of failures should include all equipment that is in the HFTD Tier 2 and 3 and all equipment that is in the utility defined HFRA beyond the HFTD.

Table SCE 8-01: Equipment Maintenance and Repair Strategy

	Equipment Type	Asset Class[124]	Condition Monitoring: a description of how the electrical corporation monitors the condition of the equipment (e.g., human visual inspection, automated visual inspection, human sensor readings, automated sensor readings)	Maintenance Strategy: identification and brief description of the maintenance strategy (e.g. reactive, preventative, predictive, reliability-centered	Replacement/repair condition: a description of how equipment is identified for repair or replacement (e.g., time interval, inspection finding, sensor reading, predictive maintenance, data analytics, machine learning).
1	Capacitors	Distribution	• Human visual inspection: (a) Distribution Overhead (OH) Capacitor Banks' inspections are conducted by the Distribution HFRI (D-HFRI) Inspection program in accordance with GO 165. Capacitor points data is collected on a survey while aerial and/or ground inspections are being performed. (b) Distribution Underground (UG) Capacitor Banks' inspections are conducted by the Underground Detailed Inspection (UDI) program in accordance with GO 165. • Human functional inspection: SCE's Field Apparatus performs a detailed functional inspection of capacitor banks' electronic components. This is in addition to D-HFRI and UDI compliance inspections. • Automated sensor readings: SCE monitors automated capacitor banks using the Distribution Management System (DMS) for remote alarms indicating the need for repairs.	Maintenance of capacitor banks involves both reactive and preventative measures. D-HFRI, UDI, and Field Apparatus inspections are cyclical and considered preventative. Reactive inspections may occur when automated sensor readings identify an anomaly, triggering a condition-based inspection or repair. Additionally, ad-hoc patrols may identify the need for reactive repairs.	SCE's Capacitor Bank Replacement program focuses on replacing or removing failed and obsolete distribution capacitor banks identified through the D-HFRI and UDI programs, as well as Field Apparatus inspections. These inspections are conducted at specific time intervals to comply with GO 165. Additionally, the need for replacement may be identified when automated sensor readings detect an anomaly, prompting a condition-based inspection that could lead to repair or replacement. Lastly, ad-hoc patrols may identify the need for inspections, potentially triggering a replacement request.
		Substation	Predictive Maintenance Assessment (PMA): The PMA process is an assessment of substation apparatus equipment by means of visual, infrared thermography and ultrasonic inspection through the use of drones and specialized analysis tools that can detect hot equipment/ connections and vibration anomalies and also determine apparatus air and gas leaks. GO 174 compliance requires Grid Operations to perform routine substation inspections and document anomalies that may affect safety and reliability. SCE complies with GO 174 by assessing, addressing, and implementing corrective actions to the found anomalies.	Reactive, preventative, predictive, and reliability-centered maintenance. Condition-based by analyzing the equipment to determine asset health. Time-based: managing equipment maintenance based on a prescribed time frame. Criteria-based: maintenance is based upon triggers and alerts.	Preventive/Predictive: Capacitors are replaced based on inspections and condition of equipment: •Replace and/or balance the capacitors •Fiber optic repair and attenuation readings
2	Circuit Breakers	Substation	PMA: See definition of PMA process above. Circuit Breaker Analysis (CBA) process is a diagnosis of a circuit breaker's electrical and mechanical performance specific to the circuit breaker make and model. Thorough analysis of the CBA waveform, it is possible to recognize potential problems before a failure occurs.	Reactive, preventative, predictive, and reliability-centered maintenance. Condition-based by analyzing the equipment to determine asset health, by way of our Maintenance Programs. Time-based: managing equipment maintenance based on a prescribed time frame.	1. Predictive: CB health index data to inform replacement. 2. Reactive: replacement due to equipment failures and/or other electric system conditions. Preventive/Predictive: SCE leverages circuit breaker (CB) health index data which includes asset age, manufacturer ratings, capacity, inspections, repairs, maintenance records, test results and performance history and short

124 Some equipment types are not applicable to asset classes in this table. For Transmission, there are no capacitors, circuit breakers, fuses, distribution poles, reclosers and transformers. For Distribution, there are no circuit breakers and transmission poles/towers. For Substations, there are no reclosers or distribution/transmission poles.

	Equipment Type	Asset Class[124]	Condition Monitoring: a description of how the electrical corporation monitors the condition of the equipment (e.g., human visual inspection, automated visual inspection, human sensor readings, automated sensor readings)	Maintenance Strategy: identification and brief description of the maintenance strategy (e.g. reactive, preventative, predictive, reliability-centered	Replacement/repair condition: a description of how equipment is identified for repair or replacement (e.g., time interval, inspection finding, sensor reading, predictive maintenance, data analytics, machine learning).
			Oil Circuit Breaker Analysis (OCBA) process determines the condition of the internal components of an oil circuit breaker. The process incorporates an in-depth evaluation of the dissolved gases, metals, and particulates in the oil. The process to generate a work request to draw an oil sample is initiated by three specific triggers: the amount of time since the breaker was last sampled, the number of operations, or the number of fault operations. Adherence to GO 174 compliance routine substation inspections.	Criteria-based: maintenance is based upon triggers and alerts.	circuit duty to make informed decision making on CB replacement.
3	Connectors, including hotline clamps	Distribution	The D-HFRI inspection program conducts human visual inspections in compliance with General Order 165. These inspections are carried out either through aerial and/or ground methods.	Maintenance of connectors, including hotline clamps, are both reactive and preventative. D-HFRI inspections are cyclical and considered preventative. Reactive inspections occur when ad hoc patrols identify the need for repairs.	Preventive/Predictive: Connectors, including hotline clamps, are replaced based on inspections and condition of equipment.
		Transmission	Transmission HFRI (T-HFRI) ground and aerial inspections Automated Sensor Readings: Early Fault Detection, IR Inspections & Corona Scanning.	Reactive and preventative.	Inspection finding, sensor reading.
		Substation	PMA: See definition of PMA process above. Adherence to G.O. 174 compliance requires for routine substation inspections.	Reactive, preventative, predictive, and reliability-centered maintenance.	Preventive/Predictive: Connectors, including hotline clamps, are replaced based on inspections and condition of equipment.

	Equipment Type	Asset Class[124]	Condition Monitoring: a description of how the electrical corporation monitors the condition of the equipment (e.g., human visual inspection, automated visual inspection, human sensor readings, automated sensor readings)	Maintenance Strategy: identification and brief description of the maintenance strategy (e.g. reactive, preventative, predictive, reliability-centered	Replacement/repair condition: a description of how equipment is identified for repair or replacement (e.g., time interval, inspection finding, sensor reading, predictive maintenance, data analytics, machine learning).
4	Conductor, including covered conductor	Distribution	D-HFRI ground inspections and aerial inspections, infrared, patrols, and LiDAR. These distribution inspection types are designed to meet or exceed GO 95 and GO 165, and also to mitigate wildfire risk. In addition, Automated Sensor Readings such as Early Fault Detection (EFD).	Maintenance of conductor, including covered conductor, involves both reactive and preventative measures. Inspections are cyclical and considered preventative. Reactive inspections may occur when automated sensor readings identify an anomaly, triggering a condition-based inspection or repair. Additionally, ad-hoc patrols may identify the need for reactive repairs.	SCE's Overhead Conductor Program (OCP) and Wildfire Covered Conductor Program (WCCP) both utilize risk models to identify overhead conductors for replacement. The OCP's risk model focuses on overhead conductor segments, primarily outside of HFRA, that can reduce public safety risks and enhance reliability. The WCCP employs a Probability of Ignition (POI) model and targets overhead circuit segments within HFRA. Additionally, conductors may be replaced through SCE's Worst Performing Circuit (WPC) program, which targets circuits, regardless of their location, where customers face reliability issues. Furthermore, the need for replacement or repair might be identified as a result of inspection findings, or when automated sensor readings detect anomalies, prompting condition-based inspections. Lastly, ad-hoc patrols may also identify the need for replacement or repair, such as in the case of a wire-down incident.
		Transmission	T-HFRI ground and aerial inspections. Automated Sensor Readings: Early Fault Detection, IR Inspections & Corona Scanning as needed.	Reactive and preventative.	Inspection finding and Proactive Transmission Overhead Conductor Replacement Program focused on small wire and aged conductor under the Transmission IR Program.
		Substation	PMA: See definition of PMA process above. Adherence to GO 174 compliance for routine substation inspections.	Reactive, preventative, predictive, and reliability-centered maintenance.	Predictive: Conductors replacements are included with circuit breakers and power transformers replacements.
5	Fuses, including expulsion fuses	Distribution	The D-HFRI program conducts human visual inspections in compliance with GO 165. These inspections are carried out either through aerial and/or ground methods.	Maintenance of fuses, including expulsion fuses are both reactive and preventative. D-HFRI inspections are cyclical and considered preventative. Reactive inspections occur when ad hoc patrols identify the need for repairs.	Preventive/Predictive: Fuses, including explosion fuses are replaced based on inspections and condition of equipment.
		Substation	PMA: See definition of PMA process above. Adherence to GO 174 compliance for routine substation inspections.	Reactive, preventative, predictive, and reliability-centered maintenance.	Preventive/Predictive: Fuses are replaced based on inspections and condition of equipment.

	Equipment Type	Asset Class[124]	Condition Monitoring: a description of how the electrical corporation monitors the condition of the equipment (e.g., human visual inspection, automated visual inspection, human sensor readings, automated sensor readings)	Maintenance Strategy: identification and brief description of the maintenance strategy (e.g. reactive, preventative, predictive, reliability-centered	Replacement/repair condition: a description of how equipment is identified for repair or replacement (e.g., time interval, inspection finding, sensor reading, predictive maintenance, data analytics, machine learning).
6	Distribution pole	Distribution	The D-HFRI ground/aerial inspection program conducts human visual inspections in compliance with GO 165. These inspections are carried out either through aerial and/or ground methods. SCE's Intrusive Pole Inspection Program (IPI) is designed to enhance safety, quality, and efficiency by inspecting poles for degradation in accordance with GO 165. Additionally, SCE's Field Apparatus perform a visual inspection on poles with attached apparatus equipment.	Distribution poles' maintenance strategy is both reactive and preventative. D-HFRI, IPI, and Field Apparatus inspections are cyclical and considered preventative. Additionally, ad-hoc patrols may identify the need for reactive repairs.	Inspection finding can result in a replacement or repair, ad-hoc field inspections.
7	Lightning arrestors	Distribution	The D-HFRI ground/aerial inspection program conducts human visual inspections in compliance with GO 165. These inspections are carried out either through aerial and/or ground methods.	Reactive and preventative. Reactive replacements are conducted as inspection findings identify the need for replacement. Preventative replacements occur as opportunity work for bundling efforts.	Inspection finding can result in a replacement or repair, ad-hoc field inspections.
		Transmission	Ground and Aerial inspections.	Reactive and preventative.	Inspection finding and Proactive pothead replacement activity under the Transmission IR Program.
		Substation	PMA: See definition of PMA process above. Adherence to GO 174 compliance for routine substation inspections.	Reactive, preventative, predictive, and reliability-centered maintenance.	Preventive/Predictive: Lighting arrestors are replaced based on inspections and condition of equipment.
8	Reclosers	Distribution	The D-HFRI ground/aerial inspection program conducts human visual inspections in compliance with GO 165. These inspections are carried out either through aerial and/or ground methods. SCE's Field Apparatus performs a detailed functional inspection.	Reactive and preventative. Reactive replacements are conducted as inspection findings identify the need for replacement. Preventative replacements occur as opportunity work for bundling efforts.	Inspection finding can result in a replacement or repair, ad-hoc field inspections.
9	Splices	Distribution	The D-HFRI ground/aerial inspection program conducts human visual inspections in compliance with GO 165. These inspections are carried out either through aerial and/or ground methods. The UDI program conducts human visual inspections in compliance with GO 165. These inspections are carried out through ground methods.	Maintenance of splices is both reactive and preventative. D-HFRI and UDI inspections are cyclical and considered preventative. Reactive inspections occur when ad hoc patrols identify the need for repairs.	Inspection finding can result in replacement or repair, ad-hoc field inspections. These can also be replaced or repaired if bundled with programmatic work such as with the OCP or the WCCP.
		Transmission	T-HFRI ground and aerial inspections. Automated Sensor Readings: IR Inspections & Corona Scanning.	Reactive and preventative. Transmission grid Capital Maintenance. Proactively shunting splices under SH-20 activity.	Inspection finding.
10	Transmission poles/towers	Transmission	Ground and Aerial inspections Automated Sensor Readings: IR Inspections & Corona Scanning.	Reactive and preventative. Transmission Grid Capital Maintenance.	Inspection finding.

	Equipment Type	Asset Class[124]	Condition Monitoring: a description of how the electrical corporation monitors the condition of the equipment (e.g., human visual inspection, automated visual inspection, human sensor readings, automated sensor readings)	Maintenance Strategy: identification and brief description of the maintenance strategy (e.g. reactive, preventative, predictive, reliability-centered	Replacement/repair condition: a description of how equipment is identified for repair or replacement (e.g., time interval, inspection finding, sensor reading, predictive maintenance, data analytics, machine learning).
11	Transformers	Distribution	The D-HFRI ground/aerial inspection program conducts human visual inspections in compliance with GO 165. These inspections are carried out either through aerial and/or ground methods. Infrared (IR) inspections are performed on transformers. The UDI program conducts human visual inspections in compliance with GO 165. These inspections are carried out through ground methods. Additionally, the Reliability Operations Center (ROC) has created several operational algorithms such as "early damage detection" for replacing transformers on the verge of failure, as well as "asset defect detection" that utilizes image recognition to find damaged equipment.	Reactive, preventative, predictive, and reliability-centered maintenance. The maintenance of transformers is both reactive and preventative. D-HFRI, UDI, and IR inspections are cyclical and considered preventative. Reactive inspections occur when ad hoc patrols identify the need for repairs.	Inspection finding can result in a replacement or repair, ad-hoc field inspections.
		Substation	PMA: See definition of PMA process above. Oil Tap-Changer Analysis (OTA) process determines the condition of a Load-Tap Changer (LTC) without having to intrusively inspect the unit. It is an oil diagnostic test that evaluates dissolves gases in LTC oil. Transformer Oil Analysis (TOA) is a critical maintenance program used to assess the health and condition of transformers. It involves analyzing the oil within transformers to detect dissolved gases, which can indicate various types of faults or degradation. This analysis helps in identifying potential issues before they lead to failures Adherence to GO 174 compliance requires routine substation inspections.	Reactive, preventative, predictive, and reliability-centered maintenance. Condition-based by analyzing the equipment to determine asset health, by way of our Maintenance Programs. Time-based: managing equipment maintenance based on a prescribed time frame. Criteria-based: maintenance is based upon triggers and alerts.	Preventive/Predictive: SCE leverages power transformer health index data which includes asset age, manufacturer ratings, capacity, inspections, repairs, maintenance records, test results and performance history to make informed decision making on transformers replacement Beginning in 2025, SCE will target heat-driven proactive replacement for distribution transformers. Transformers are at risk of failure during heat waves due to temperature stress on electrical components. Specifically, external heat can prevent the transformer winding insulation from cooling properly, escalating transformer winding insulation breakdown and leading to failure.
12	Non-exempt equipment	Distribution, Transmission & Substation	N/A - dependent on approach to monitoring the primary structure.	N/A – dependent on the approach to maintaining the primary structure.	Inspection findings and preventative maintenance as work bundling opportunities.
13	Pre-GO 95 legacy equipment	Distribution, Transmission & Substation	N/A	N/A	N/A

	Equipment Type	Asset Class[124]	Condition Monitoring: a description of how the electrical corporation monitors the condition of the equipment (e.g., human visual inspection, automated visual inspection, human sensor readings, automated sensor readings)	Maintenance Strategy: identification and brief description of the maintenance strategy (e.g. reactive, preventative, predictive, reliability-centered	Replacement/repair condition: a description of how equipment is identified for repair or replacement (e.g., time interval, inspection finding, sensor reading, predictive maintenance, data analytics, machine learning).
14	Other equipment not listed	Distribution, Transmission & Substation	PMA: See definition of PMA process above. GO 174 compliance requires Grid Operation's to perform routine substation inspections and document anomalies that may affect safety and reliability. SCE/Substation Construction & Maintenance (SC&M) AOR complies with GO 174 by assessing, addressing, and implementing corrective actions to the found anomalies.	Reactive, preventative, predictive, and reliability-centered maintenance. Condition-based by analyzing the equipment to determine asset health, by way of our Maintenance Programs. Time-based: managing equipment maintenance based on a prescribed time frame. Criteria-based: maintenance is based upon triggers and alerts.	Preventive/Predictive: Other substation equipment is replaced based on inspections and conditions of equipment. Transmission Switch Replacmenet program under Transmission IR

Table SCE 8-02: List of Possible Findings, Priority Level and Timeframe for Remediation

Equipment type	Asset Class	Priority[125]	Possible Conditions/Findings (Representative Sample)
Capacitor	Distribution	1	Replace damaged primary capacitor switch
		2	Repair damaged primary capacitor switch
			Repair damaged public capacitor switch
	Substation	2	Repair damaged/broken capacitor circuit breaker
			Repair damaged/broken capacitor switcher
		3	Repair damaged/broken capacitor switcher
			Repair open/short circuit capacitor circuit breaker
Circuit breaker	Substation	2	Repair abnormal breaker circuit breaker
			Repair failed to close breaker circuit breaker
Conductor	Distribution	1	Replace damaged public cable/conductor streetlight pole
			Replace damaged secondary cable/conductor streetlight pole
		2	Replace damaged secondary cable/conductor pole
			Relocate distribution transmission (Combo) primary cable/conductor pole
		3	Repair bare service cable/conductor pole
			Repair corroded comm cable/conductor pole
	Substation	2	Repair abnormal conductor switch rack
			Repair burned conductor switcher
		3	Repair abnormal conductor circuit breaker
	Transmission	1	Repair corroded transmission conductor cable/conductor pole
			Repair damaged transmission conductor cable/conductor pole
		2	Repair damaged/corroded transmission conductor cable/conductor pole
			Repair damaged public cable/conductor pole
		3	Repair damaged public cable/conductor pole
Connector	Distribution	1	Repair corroded primary connector transformer
			Repair corroded secondary connector pole
		2	Install damaged primary connector pole
			Repair corroded secondary connector pole
	Substation	2	Replace/Remove other conductor cable-connector switch rack
	Transmission	1	Repair excessive heat transmission conductor connector pole
		2	Repair corroded transmission conductor connector pole
			Repair damaged transmission conductor connector pole
		3	Repair damaged/loose transmission conductor connector pole
Fuse	Distribution	1	Repair damaged primary, branch line fuse
			Repair damaged primary cut/ branch line fuse
		2	Install missing primary cut/fuse pole
			Repair corroded/damaged primary cut/fuse pole
	Substation	1	Adjust/service abnormal primary fuse cap
			Repair abnormal fuse circuit breaker
		2	Repair abnormal disc-fuse switch rack
			Repair abnormal fuse circuit breaker
		3	Repair abnormal primary fuse capacitor
			Repair open/short circuit fuse switch rack
	Transmission	1	Replace damaged primary cut/fuse pole
Lightning arrestor	Distribution	1	Repair damaged primary lightning arrestor pole
			Repair damaged primary lightning arrestor rec
		2	Install damaged/missing primary lightning arrestor pole
		3	Repair damaged primary lightning arrestor pole
	Substation	2	Repair damaged/broken lightning arrestor circuit breaker
	Transmission	2	Replace damaged transmission conductor lightning arrestor pole
Other equipment not listed	Distribution	1	Repair corroded primary switch
			Repair damaged/loose primary switch
			Repair excessive heat primary switch
		2	Repair corroded primary switch
			Repair damaged primary switch
	Transmission	1	Replace damaged transmission conductor pot head
		2	Repair damaged transmission conductor switch
			Repair loose transmission conductor switch
Distribution Pole	Distribution	1	Repair damaged primary pole
			Repair damaged public pole
		2	Repair corroded comm pole
			Repair corroded primary pole
			Replace loose secondary pole
Recloser	Distribution	1	Remove animal nest primary recloser
			Replace damaged public control rec
		2	Remove animal nest primary recloser
			Replace damaged public recloser
Splice	Distribution	1	Repair damaged primary splice pole
			Replace excessive heat service splice pole
		2	Repair damaged primary splice pole
			Repair damaged secondary splice pole
		3	Repair corroded secondary splice pole
	Transmission	1	Repair corroded transmission conductor splice tower

125 Timeframe for remediation: P1 – the condition is made safe within 24 hours and remediation work commences within 72 hours. P2 – condition is remediated within 6 months for HFRA Tier 3, within 12 months for HFRA Tier 2, and within 36 months for non-ignition risk notifications. P3 within 60 months. SCE's timeframe for remediation is applied to all equipment types included in section 8.4, including Non-Exempt Equipment, Pre-GO95 Legacy Equipment and Other Equipment Not Listed.

Equipment type	Asset Class	Priority[125]	Possible Conditions/Findings (Representative Sample)
			Repair damaged transmission conductor splice pole
		2	Repair corroded/damaged transmission conductor splice tower
		3	Repair damaged transmission conductor splice pole
Transformer	Distribution	1	Repair damaged primary potential transformer
			Repair damaged primary potential transformer
		2	Repair corroded primary hardware/framing transformer-d
		3	Repair corroded primary transformer-d
	Substation	1	Repair abnormal current transformer circuit breaker
		2	Add oil leaking potential transformer switch rack break down
			Repair abnormal current transformer circuit breaker
		3	Replace/Remove abnormal current transformer switch rack
Transmission pole/ tower	Transmission	1	Repair corroded public pole/tower
			Repair damaged public pole/tower
		2	Repair corroded public pole/tower
			Repair damaged public pole/tower
		3	Repair damaged public pole/tower
			Repair damaged transmission conductor skyline tower

Note: SCE utilizes PRC 4292 and 4293 guidelines to determine Non-Exempt Equipment. These Non-Exempt Equipment includes, but are not limited to, certain types of switches, fuses and lightning arrestors. Please refer to list of possible conditions above for the following equipment type: Fuses, Lightning Arrestors and Other Equipment (which includes switches).
SCE does not have any equipment designated as Pre-GO95 legacy equipment as all equipment are subject to GO95 requirements.

Table SCE 8-03: Equipment Maintenance and Repair Failure Rate[126]

		2022			2023			2024		
Equipment Type[127,128]	**Asset Class**	**Notification**	**Total Equipment Count**	**Failure Rate**	**Notification**	**Total Equipment Count**	**Failure Rate**	**Notification**	**Total Equipment Count**	**Failure Rate**
Capacitors	**Distribution**	6	1,726	0.35%	7	1,704	0.41%	1	1,665	0.06%
	Substation	0	93	0.00%	1	94	1.06%	3	112	2.68%
Circuit Breaker	**Substation**	8	3,224	0.25%	5	3,165	0.16%	14	3,233	0.43%
Connectors, including hotline clamps	**Distribution**	73	N/A	N/A	86	N/A	N/A	62	N/A	N/A
	Transmission	3	N/A	N/A	5	N/A	N/A	3	N/A	N/A
	Substation	6	N/A	N/A	1	N/A	N/A	7	N/A	N/A
Conductor, including CC[129] (Use OH Miles)	**Distribution**	640	58,929	1.08%	878	58,929	1.49%	621	58,929	1.05%
	Transmission	7	12,735	0.05%	13	12,735	0.10%	10	12,735	0.08%
	Substation	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Fuses, including expulsion fuses	**Distribution**	49	17,970	0.27%	59	18,119	0.33%	43	18,082	0.24%
	Substation	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Distribution Pole	**Distribution**	173	302,826	0.06%	269	296,625	0.09%	158	287,601	0.05%
Lightning Arrestors	**Distribution**	32	N/A	N/A	38	N/A	N/A	68	N/A	N/A
	Transmission	2	N/A	N/A	3	N/A	N/A	2	N/A	N/A
	Substation	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Reclosers	**Distribution**	8	964	0.83%	11	981	1.12%	3	960	0.31%
Splices	**Distribution**	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	Transmission	N/A	N/A	N/A	3	N/A	N/A	2	N/A	N/A
	Substation	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Transmission Poles/Towers	**Transmission**	11	39,880	0.03%	15	38,667	0.04%	11	37,806	0.03%
Transformers	**Distribution**	396	87,812	0.45%	372	88,150	0.42%	345	87,451	0.39%
	Substation	0	459	0.00%	3	457	0.66%	5	449	1.11%
Non-exempt equipment	**All**	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Pre-GO 95 legacy equipment[130]	**All**	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Other Equipment Not Listed (Switch, Pothead)	**Distribution**	38	8,296	0.46%	27	8,396	0.32%	31	8,461	0.37%
	Transmission	1	612	0.16%	1	603	0.17%	1	596	0.17%
	Substation	0	129	0.00%	0	129	0.00%	0	130	0.00%

126 Notification in this table refers to P1 notifications that are used as a proxy for equipment failure. This excludes P1 notifications resulting from external circumstances such as car hit pole, mylar balloons, animal contact, natural disasters, etc.
127 Some equipment types are not applicable to asset classes in this table. For Transmission, there are no capacitors, circuit breakers, fuses, distribution poles, reclosers and transformers. For Distribution, there are no circuit breakers and transmission poles/towers. For Substations, there are no reclosers or distribution/transmission poles.
128 The following equipment types: connectors, lightning arrestors, splices, non-exempt equipment, can be considered B-materials and do not meet threshold for being individually tracked and inventoried, hence, the total equipment count is not captured in SCE's system of record. B-materials are often used as enabling components to assemble main components of assets or are considered sub-components. Notifications for splices are typically recorded to the conductor or structure if a detailed investigation hasn't yet occurred that identified the splice as the cause of the failure.
129 Overhead circuit miles for conductor/covered conductor includes circuit miles for primary and secondary conductor.
130 Not applicable. SCE considers all equipment as subject to GO 95 requirements.

Table SCE 8-04: Equipment Maintenance and Repair Ignition Rate

		2019			2020			2021			2022			2023			2024		
Equipment Category	Voltage Type	Ignition Count	Failure Count	Ignition Rate	Ignition Count	Failure Count	Ignition Rate	Ignition Count	Failure Count	Ignition Rate	Ignition Count	Failure Count	Ignition Rate	Ignition Count	Failure Count	Ignition Rate	Ignition Count	Failure Count	Ignition Rate
Capacitors	**Distribution**	0	0	N/A	0	1	0%	0	3	0%	0	6	0%	0	7	0%	0	1	0%
	Transmission	0	0	N/A	0	0	N/A	0	0	N/A	0	0	N/A	0	0	N/A	0	0	N/A
	Substation	0	0	N/A	0	0	N/A	0	1	0%	0	0	N/A	0	1	0%	0	3	0%
Circuit Breakers	**Distribution**	0	0	N/A	0	2	0%	0	0	N/A	0	0	N/A	0	0	N/A	0	0	N/A
	Transmission	0	0	N/A	0	0	N/A	0	0	N/A	0	0	N/A	0	0	N/A	0	0	N/A
	Substation	0	0	N/A	0	0	N/A	0	0	N/A	0	8	0%	0	5	0%	0	14	0%
Connectors, including hotline clamps	**Distribution**	3	80	4%	5	50	10%	9	60	15%	2	73	3%	1	86	1%	3	62	5%
	Transmission	1	4	25%	0	2	0%	0	5	0%	0	3	0%	0	5	0%	0	3	0%
	Substation	0	1	0%	0	1	0%	0	0	N/A	0	6	0%	0	1	0%	0	7	0%
Conductor, including CC	**Distribution**	8	1116	1%	9	777	1%	7	692	1%	6	640	1%	3	878	0%	5	621	1%
	Transmission	0	25	0%	0	9	0%	0	17	0%	1	7	14%	2	13	15%	1	10	10%
	Substation	0	1	0%	0	0	N/A	0	0	N/A	0	0	N/A	0	0	N/A	0	0	N/A
Fuses, including expulsion fuses	**Distribution**	1	127	1%	0	86	0%	1	89	1%	1	49	2%	0	59	0%	1	43	2%
	Transmission	0	2	0%	0	1	0%	2	0	N/A	0	0	N/A	0	2	0%	0	3	0%
	Substation	0	1	0%	0	0	N/A	0	0	N/A	0	0	N/A	0	0	N/A	0	0	N/A
Pole	**Distribution**	2	580	0%	1	301	0%	0	172	0%	1	173	1%	0	269	0%	1	158	1%
	Transmission	0	46	0%	0	25	0%	0	14	0%	0	11	0%	0	15	0%	0	11	0%
	Substation	0	0	N/A	0	0	N/A	0	0	N/A	0	0	N/A	0	0	N/A	0	0	N/A
Lightning Arrestors	**Distribution**	0	56	0%	0	43	0%	0	49	0%	1	32	3%	1	38	3%	1	68	1%
	Transmission	0	5	0%	0	4	0%	0	2	0%	0	2	0%	0	3	0%	0	2	0%
	Substation	0	0	N/A	0	0	N/A	0	0	N/A	0	0	N/A	0	0	N/A	0	0	N/A
Reclosers	**Distribution**	0	3	0%	0	1	0%	0	2	0%	0	8	0%	0	11	0%	0	3	0%
	Transmission	0	0	N/A	0	0	N/A	0	0	N/A	0	0	N/A	0	0	N/A	0	0	N/A
	Substation	0	0	N/A	0	0	N/A	0	0	N/A	0	0	N/A	0	0	N/A	0	0	N/A
Splices[131]	**Distribution**	0	0	N/A	0	0	N/A	0	0	N/A	0	0	N/A	0	0	N/A	0	0	N/A
	Transmission	0	0	N/A	0	0	N/A	0	0	N/A	0	0	N/A	0	3	0%	0	2	0%
	Substation	0	0	N/A	0	0	N/A	0	0	N/A	0	0	N/A	0	0	N/A	0	0	N/A
Transformers	**Distribution**	0	556	0%	2	537	0%	3	429	1%	2	396	1%	3	372	1%	1	345	0%
	Transmission	0	0	N/A	0	0	N/A	0	0	N/A	0	0	N/A	0	0	N/A	0	0	N/A
	Substation	0	3	0%	0	2	0%	0	4	0%	0	0	N/A	0	3	0%	0	5	0%
Non-exempt equipment	**Distribution**	0	0	N/A	0	0	N/A	0	0	N/A	0	0	N/A	0	0	N/A	0	0	N/A
	Transmission	0	0	N/A	0	0	N/A	0	0	N/A	0	0	N/A	0	0	N/A	0	0	N/A
	Substation	0	0	N/A	0	0	N/A	0	0	N/A	0	0	N/A	0	0	N/A	0	0	N/A
Pre-GO 95 legacy equipment	**Distribution**	0	0	N/A	0	0	N/A	0	0	N/A	0	0	N/A	0	0	N/A	0	0	N/A
	Transmission	0	0	N/A	0	0	N/A	0	0	N/A	0	0	N/A	0	0	N/A	0	0	N/A
	Substation	0	0	N/A	0	0	N/A	0	0	N/A	0	0	N/A	0	0	N/A	0	0	N/A
Other Equipment Not Listed[132]	**Distribution**	1	74	1%	2	36	6%	4	28	14%	6	38	16%	4	27	15%	4	31	13%
	Transmission	1	1	N/A	1	1	N/A	0	0	N/A	1	1	N/A	0	1	N/A	0	1	N/A
	Substation	0	0	N/A	0	0	N/A	0	0	N/A	0	0	N/A	0	0	N/A	0	0	N/A

131 Failure and ignition data for splices are typically recorded to the conductor or structure if a detailed investigation hasn't yet occurred that identified the splice as the cause of the failure.
132 Ignition rate is not applicable to the transmission asset class in "other equipment not listed" category due to the different equipment types included. For example, the equipment failures recorded were for potheads or switches while the ignition count was related to other equipment types such as insulators.

- ***Failure and ignition causes:*** *A narrative describing root cause analyses performed for failures and associated CPUC ignitions within the HFTD and HFRA, including any lessons learned and solutions implemented to decrease ignition rates.*

SCE conducts root cause analyses for failures and associated CPUC reportable ignitions within HFRA. An overview of SCE's efforts to analyze root causes of ignitions, implement lessons learned, and deploy solutions to decrease ignition rates within HFRA are outlined below.

Fire Incident Preliminary Analysis (FIPA): SCE's FIPA process provides root cause analysis and engineering reviews of CPUC reportable ignitions and identifies the drivers that may have caused the ignitions. An engineering evaluation is performed to understand whether there were mitigations in place to address the underlying cause of the risk event and whether that mitigation performed as intended. SCE also identifies improvements to reduce the likelihood of recurrence, improve mitigation actions, and improve operational procedures and practices. This includes selecting and evaluating new grid monitoring technologies or systems based on an identified need and/or the mitigation's overall effectiveness at risk reduction. For instance, SCE may determine that a new system or mitigation is required when, upon review and analysis of ignition and fault data on the grid, it becomes apparent that one or more drivers of ignitions/faults cannot be adequately addressed using existing mitigations or a better mitigation may be available if proved to be effective.

SCE uses the FIPA process to monitor and review data, such as outages and wire downs, to assess the performance of wildfire mitigation programs and to identify opportunities to enhance those programs. For example, the FIPA process has contributed to updates to asset inspection survey questions, updates to design criteria for 66kV transmission structures, and a pilot for vegetation management related to secondary conductor.

Solutions Implemented to Decrease Ignition Rates Resulting from FIPA:

Asset Inspection Survey: SCE continuously evaluates and makes updates to its asset inspection survey to identify and remediate potential ignition risks. For example, in 2021, SCE included additional questions to improve identification of issues with guy anchors, secondary and services, and notifications to communication infrastructure providers. In 2023 and 2024, SCE also included additional questions to improve identification of issues related to covered conductor corrosion and surface damage. In addition, SCE updated questions to assist inspectors in identifying vegetation clearance that would optimize the Vegetation Management efforts.

Transmission Enhanced System Design: In 2026-2028, SCE is implementing the Enhanced System Design (ESD) pilot program to harden 66kV structures in Severe Risk Areas and reduce wildfire hazards. The updated engineering standards use 115kV design criteria and incorporate resilient steel structures to prevent ignition events caused by object contact. Please refer to section 8.2.13.1 Transmission Enhanced System Design for additional details.

Vegetation Management: SCE's vegetation management activities aim to reduce the risk of vegetation-related ignitions by maintaining required clearances and removing hazardous trees. Since 2021, SCE has been exploring enhancements to its vegetation management activities around secondary conductors based on insights gained from the FIPA process. The approach involves inspecting and trimming vegetation around secondary conductors to provide enhanced clearances within HFRA.

8.5 Quality Assurance and Quality Control

8.5.1 Overview, Objectives, and Targets

In this section, the electrical corporation must provide an overview of each of its QA and QC activities for grid design, asset inspections and maintenance. This overview must include the following for each program:

- *Initiative/activity being audited (each initiative/activity name must correspond to an initiative/activity described in Sections 8.2 - 8.4)*
- *Tracking ID from Table 8.1 or 8.2*
- *Quality program type (QA or QC)*
- *Objective of each QA and QC program*

Table 8-3 provides an example of the required level of detail. At a minimum, Table 8-3 must include the following types of activities: new construction, corrective repair work, asset inspections (as described in Section 8.3), and any additional asset maintenance.

Table 8-3: Grid Design, Asset Inspections, and Maintenance QA and QC Program Objectives

Initiative/Activity Being Audited	Tracking ID	Quality Program Type	Objective of the Quality Program
Distribution High Fire Risk-Informed (HFRI) Inspections - Ground and Aerial	IN-1.1	QC	Conduct QC review of distribution detailed ground inspections in HFRA Tier 2 and Tier 3
Transmission High Fire Risk-Informed (HFRI) Inspections-Ground and Aerial	IN-1.2	QC	Conduct QC review of transmission ground detailed inspections in HFRA Tier 2 and Tier 3
Generation High Fire Risk-Informed (HFRI) Inspections	IN-5	QC	Conduct QC review of generation inspections in HFRA Tier 2 and Tier 3
Distribution Construction	Various[133]	QC	Conduct QC review of distribution construction activities in HFRA Tier 2 and Tier 3
Transmission Construction	Various[134]	QC	Conduct QC review of transmission construction activities in HFRA Tier 2 and Tier 3

133 Construction and corrective repair quality control (QC) reviews occur territory wide, with a scope that includes both wildfire-driven activities as well as non-wildfire utility asset work.

134 Refer to footnote above regarding construction and corrective repair QC.

The electrical corporation must also provide the following tabular information for each QA and QC program:

- *Initiative/activity being audited (each initiative/activity name must correspond to an initiative/activity described in Sections 8.2 - 8.4)*
- *Type of audit (e.g. desktop or field)*
- *Population[135]/sample unit*
- *Population size for each audited initiative/activity for each year of the three-year WMP cycle*
- *Sample size for each audited initiative/activity for each year of the three-year WMP cycle*
- *Percent of sample in the HFTD for each audited initiative/activity for each year of the three-year WMP cycle*
- *Confidence level and Margin of Error (MOE)*
- *Target pass rate for each audited initiative/activity for each year of the three-year WMP cycle*

Table 8- 4 provides an example of the appropriate level of detail and required format. At a minimum, Table 8- 4 must include the following types of activities: new construction, corrective repair work, asset inspections (as described in Section 8.3), and any additional asset maintenance.

Table 8- 4 below shows the inspection and construction related QC programs that SCE undertakes within HFRA. These QC programs are intended to evaluate inspection and construction activities for conformance to GO requirements and SCE's standards. For SCE's inspection programs, a QC inspection is conducted by evaluating the results of completed inspections. Results from QC analysis can inform understanding of the status of programs, help identify challenges and root causes and identify issues that need follow-up actions. Actionable findings identified during QC inspections are used for performance scoring to measure the ability of SCE inspectors to accurately identify and classify the potential safety and reliability risks of GO 95 violations, potential ignition risks, and other safety hazards. All findings identified during the QC review are remediated, and in some instances, corrective actions are initiated.

SCE's QC function for new construction and corrective repair work is deployed for SCE's entire service territory and is functionally the same both within and outside of HFRA. SCE takes this approach as new construction and corrective repair work should be performed consistent with expectations and standards regardless of whether it is within or outside of HFRA. SCE's HFRI inspections and corresponding QC programs are intended to identify and address wildfire risk posed by utility assets within HFRA that would not be present if those assets were not in HFRA.

135 In this section, a population may be the number of circuit miles inspected, the number of assets inspected, etc.

Table 8-4: Grid Design, Asset Inspections, and Maintenance QA and QC Activity Targets[136]

Initiative/ Activity Being Audited	Type of Audit	Population /Sample Unit	2026: Population Size	2026: Sample Size	2027: Population Size	2027: Sample Size	2028: Population Size	2028: Sample Size	Percent of Sample in the HFTD	Confidence level / MOE	2026: Pass Rate Target	2027: Pass Rate Target	2028: Pass Rate Target
Distribution High Fire Risk-Informed (HFRI) Inspections	Field	Asset Inspection	206,000	2,375	206,000	2,375	206,000	2,375	100%	97%/3%	94%	94%	94%
Transmission High Fire Risk-Informed (HFRI) Inspections	Field	Asset Inspection	27,700	500	27,700	500	27,700	500	100%	96%/3%	94%	94%	94%
Generation High Fire Risk-Informed (HFRI) Inspections	Field	Asset Inspection	160	125	170	125	160	125	100%	96%/3%	94%	94%	94%
Distribution Construction[137]	Field	Construction Inspection	~10,400[138]	1600	~10,400	1600	~10,400	1600	100%	97%/2%	91%	91%	91%
Transmission Construction[139]	Field	Construction Inspection	125[140]	77	125	77	125	77	100%	97%/3%	94%	94%	94%

136 Sample size in the table below may vary dependent on annual population size for construction QC programs. All QC activity pass rates are subject to review based on the result from the previous year.
137 Distribution Construction and corrective repair QC are conducted territory wide and can include the WMP programs in HFRA discussed in chapter 8. Sample size covers work in HFRA and may include non-wildfire specific programs. Sampling is not done on specific programs but on completed work in HFRA.
138 Distribution Construction sample size for 2026-2028 is based on the scope of construction activities. It may be difficult to merge various construction activities together due to the different construction scopes involved for small and large projects.
139 Transmission Construction and corrective repair QC are conducted territory wide and can include the WMP programs in HFRA discussed in chapter 8. Sample size covers work in HFRA and may include non-wildfire specific programs. Sampling is not done on specific programs but on completed work in HFRA.
140 Transmission Construction sample size for 2026-2028 is based on the scope of construction activities. It may be difficult to merge various construction activities together due to the different construction scopes involved for small and large projects.

8.5.2 QA and QC Procedures

In this section, the electrical corporation must list the applicable procedure(s), including the version(s) and effective date(s), used for each grid design, operation, and maintenance QA and QC program listed in Table 8-3.

Supporting documentation for QA/QC activities is available at https://www.sce.com/wmp for assessments of inspection activities.

SCE's procedures for QA/QC are outlined in the following documents:

- Overhead Detailed QC Inspection Process for Distribution Equipment (QCP-006), revision 5, effective date, March 13, 2024.
- Transmission Detail QC Inspection Process for Transmission Assets (QCP-014), revision 1, effective date, March 13, 2024.
- Generation QC Inspection Process for Generation Assets (QCP-015), revision 1, effective date, March 13, 2024.
- Overhead Construction QC Inspection Process for Distribution Assets (QCP-007), revision 5, effective date, March 13, 2024.
- Overhead Construction QC Inspection Process for Transmission Assets (QCP-010), revision 5, effective date, March 13, 2024.

8.5.3 Sampling Plan

In this section, the electrical corporation must describe how it determines the sample for each QA and QC program listed in Table 8-4. This must include how HFTD tier or other risk designations affect the sampling plan, and how the electrical corporation ensures samples are representative of the population.

SCE uses a risk-based approach to determine sample size and measure performance targets, specifically focusing on Confidence Level (CL). The CL and Confidence Interval (CI) used to determine the sample size varies by risk levels, categorized from Very High to Low. SCE employs a 5x5 matrix system, where one dimension represents five levels of POI risk, and the other dimension represents five levels of consequence. These dimensions translate into risk categories for IWMS. Programs are also ranked based on complexity, potential downstream impacts, and component or structure risk. Under this methodology, SCE performs quality control reviews on both wildfire and non-wildfire activities using the defined CL/CI levels.

8.5.4 Pass Rate Calculation

In this section, the electrical corporation must describe how it calculates pass rates. This description must include:

- *The sample unit that generates the pass rate for each QA and QC program (e.g., for detailed distribution inspections, the sample unit that generates the pass rate may be a single inspection that passes or fails a QC audit).*

- *The pass and failure criteria for each initiative/activity listed in table 8-3, including a discussion of any weighted contributions to the pass rate.*

The sample unit that generates the pass rate for QC inspections is a conforming structure. A conforming structure does not have an actionable quality finding identified during the quality review or inspection; in other words, the QC inspection matched the previous inspection performed by the inspector. SCE calculates a monthly conformance rate by dividing the count of conforming structures inspected by the count of inspected structures. For example, if 95 structures are found to be conforming out of 100 structures reviewed by quality inspectors, the conformance rate would be 95%.

Depending upon the complexity of the structure, one structure may have multiple non-conformances, and only one condition needs to be identified for the structure to be deemed nonconforming. To determine conformance for the programs included in table 8-3, the QC inspector assesses adherence to GOs 95 and 128, SCE standards, and any conditions that pose potential ignition risks, and other safety hazards.

8.5.5 Other Metrics

In this section, the electrical corporation must list metrics used by the electrical corporation to evaluate the effectiveness of its QA and QC programs and procedures (e.g. audit pass rates, outage rate within six months of inspection attributed to equipment condition or failure, new construction rework rate).

Metrics that SCE uses to evaluate the effectiveness of its QA and QC programs include the number of QC inspections performed, program conformance rate details, and top findings by category. SCE tracks conformance rates, trends, and top findings that can be used to improve program performance.

8.5.6 Documentation of Findings

In this section, the electrical corporation must describe how it documents its QA and QC findings and incorporates lessons learned from those findings into corrective actions, trainings, and procedures. This must include a description of how the electrical corporation accounts for and documents the following when improving its inspections and maintenance QA and QC processes:

- *The number of inspections reviewed.*
- *The number of new issues identified.*
- *The number of repairs with a shortened deadline.*
- *The number of repairs with a longer deadline.*
- *The number of recommended repairs cancelled.*

SCE conducts regular QA/QC for inspection and construction activities, as well as routine QA/QC for certain wildfire mitigations. These QA/QC programs are designed to ensure that SCE's activities meet the requirements of SCE's programs. A QC inspection is conducted by evaluating the results of a sample of completed inspection or construction activities. The data from the various QA/QC analyses are used to understand the status of programs, help identify challenges and root causes and identify issues that need follow-up actions. Actionable findings identified during QC inspections are used for performance scoring. For example, actionable findings identified during the QC of inspection programs measure the ability of SCE's inspectors to accurately identify and classify potential safety and reliability risks. All findings identified during the QC review are remediated, and in some instances, corrective actions are initiated. SCE's QA/QC programs help drive continuous improvement by identifying nonconformances with SCE standards, determining causes of non-conformance, or driving corrective actions to improve performance. The quality program will track action plans to corrective actions, which can include changes implemented to inspection processes, training, etc., to continuously improve the inspection programs based on QA/QC findings.

All QC inspection details are documented at the program level. QC inspection records specify the structure inspected, the inspector, the date of the inspection, and any problems or items requiring corrective action identified during each inspection. The QC inspectors document the GO infraction or SCE standard that resulted in the nonconformance. Information such as the number of inspections reviewed, number and type issues identified, number of repairs with a shortened deadline, number of repairs with a longer deadline and number of repairs open or cancelled can be obtained from the QC inspection records and reports provided monthly to the business lines to inform continuous improvement opportunities.

8.5.7 Changes to QA and QC Since Last WMP and Planned Improvements

In this section, the electrical corporation must describe:

A list of changes the electrical corporation made to its QA and QC procedure(s) since its last WMP submission.

SCE periodically evaluates and updates the risk-based approach to determine sample size and measure performance targets described in Section 8.5.3. In 2024 SCE made incremental revisions to the QC sampling methodology to better allocate minimum number of inspections in different districts/regions.

Justification for each of the changes including references to lessons learned as applicable.

The incremental revisions to the QC sampling methodology implemented in 2024 were performed to allow for a more balanced/risk-based approach to sampling. This revised approach allowed SCE to expand QC activities to areas or contractors that previously had limited, or no QC inspections performed.

A list of planned future improvements and/or updates to QA and QC procedure(s) including a timeline for implementation.

SCE is piloting the use of AI models to serve as an additional quality control measure, aiding in the identification of potential issues from HFRI inspections, considering the extensive detail required from both ground and aerial inspections. These and other activities are being explored as potential technologies that may allow for QC inspectors to perform desktop QC inspections to supplement field-based QC inspections. For additional details, refer to Section 8.3.1.3.

8.6 Work Orders

In this section, the electrical corporation must provide an overview of the procedures it uses to manage its open work orders resulting from inspections that prescribe asset management activities. 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.

SCE's procedures for identifying asset conditions and managing open work orders[141] are outlined in the Distribution Inspection Maintenance Program (DIMP) and Transmission Inspection and Maintenance Program (TIMP) manuals. The DIMP and TIMP manuals are available at https://www.sce.com/wmp.

When an issue is identified through one of SCE's asset inspection programs, a notification is generated. A notification is then assigned a priority -- P1, P2, or P3 -- depending on the severity of the risk created by the identified condition, and the notification is scheduled for remediation. Consistent with GO 95, SCE makes P1 related work safe within 72 hours. P2 issues that could pose a fire risk are scheduled for remediation within 12 months in Tier 2 areas and 6 months in Tier 3 areas. P3 issues, which are low risk, and do not pose a fire risk are scheduled for remediation within 60 months.

A description of the plan for correcting any past due work orders (i.e., open work orders that have passed remediation deadlines), if applicable including the estimated date past due work orders in HFTD will be completed.

SCE has established a target (IN-11) to address past due P2 HFRA notifications that could pose an ignition risk. From 2022-2024, SCE completed over 80% of its P2 notifications on time, despite significant increases in inspection volume, scope, and findings. The overall number of P2 notifications due in the last three years (2022-2024) increased by approximately 7% from the prior three years (2019-2021) due to changes in SCE's inspection processes, such as inclusion of aerial inspections, increased inspections in HFRA, and enhanced detailed inspections.

SCE groups its P2 backlog into four categories:

- A **GO 95 exception** applies when an external constraint prevents SCE from completing work within a compliance timeframe. Several scenarios qualify for a GO 95 exception: (1) permitting, (2) third-party refusal, (3) no access, and (4) system-wide emergency. While the resolution of GO 95 exceptions is largely outside of SCE's control, SCE includes GO 95 exceptions in its backlog reporting. SCE also reviews notifications

141 SCE uses the term notifications instead of work order.

within the GO 95 Exceptions category to assess whether the notification was still constrained and could be remediated.

- A **notify third party/third party issue** notification occurs when SCE finds that a third party (either customer or a communication infrastructure provider) has created an issue that requires remediation on an SCE asset. Although SCE cannot force the third party to remediate, SCE's obligation is to notify the third party of the outstanding issue.
- An **inactive equipment/FLOC** notification occurs due to a latency in updating the system of record related to: (1) inactive equipment or functional location (FLOC); and/or (2) reject notifications. Inactive Equipment or FLOC notifications stem from errors with dispositioning inactive equipment or FLOCs in our system of records. For example, when poles and equipment are replaced or deactivated in the system of record during emergency conditions such as storm work or fire restoration, open notifications may not be promptly updated once the asset is re-activated or replaced. Reject Notifications occur when a notification is no longer needed because the issue has been resolved, but the notification is not yet closed for administrative reasons.
- A **Pending late/Other** notification signifies a notification that is past due and does not fall within the three categories defined above.

To inform the notification backlog reduction efforts, SCE provides context with recent inspection and remediation trends. In 2023-2024, SCE's distribution find rate from HFRA 360 inspections was approximately 33%, while the find rate of transmission ground and aerial inspections was approximately 7%. In 2026-2028, SCE has an annual target of 206,000 distribution inspections with a strive target of 221,000 inspections and 27,700 transmission inspections with a strive target of 28,500. Using an average find rate of 33% for distribution and 7% for transmission, this yields a potential range of 67,980 – 72,930 distribution remediations and 1,939 – 1,995 transmission remediation notifications annually in the 2026-2028 timeframe.

Given the volume of remediation notifications generated annually, some of these notifications may become past due. Based on 2024 year-end data, majority of the past due distribution notifications fall within the GO 95 exception, third-party issues, or inactive equipment/FLOC categories. The majority of transmission past due notifications fall within the GO 95 exception or inactive equipment/FLOC categories.

As explained above, SCE has established a target (IN-11) with the objective to close 70% of P2 notifications in HFRA with ignition-risk potential that are past due in the "inactive equipment/FLOC" and "other" categories on an annual basis. This approach prioritizes the highest-risk portion of the backlog in a dynamic manner and accounts for fluctuations in the backlog due to the ongoing nature of asset inspections.

A description of how work orders are prioritized based on risk.

SCE prioritizes notifications based on the severity of the findings and the associated compliance deadline, consistent with General Order 95.

SCE also incorporates a supplemental notification prioritization algorithm to accelerate remediation of the highest risk notifications in AOCs. SCE uses multiple components to risk prioritize its notifications; Probability of Ignition, potential consequence of a wildfire at the location, potential of PSPS impacting the structure, if the structure is included as an AOC, and the specifics of the notification (i.e. problem statement and age of the notification). By targeting the highest risk notifications based on the above risk prioritization criteria, SCE's backlog reduction target (IN-11) factors in these risk prioritization measures.

A description of procedures the electrical corporation uses for monitoring and/or reinspecting open work orders.

SCE uses a risk prioritization methodology for periodically reviewing open notifications (see response to the bullet point below on prioritization level within the backlog). In addition, SCE's HFRI inspection frequency is based on HFRA Tier, including AOCs. Assets with open notifications are inspected again as part of standard HFRI scheduled inspections. If an asset condition is observed to have significantly deteriorated from initial observations during a subsequent inspection in line with the HFRI inspection frequency or via a patrol, a higher priority notification could be created for remediation. For example, a P2 notification might become a P1 notification if it is inspected again before the scheduled remediation date and the asset condition is observed to have significantly deteriorated during the subsequent inspection.

A discussion of how past trends of open work orders have informed the electrical corporation's current procedures and prioritization for addressing work orders. This must include analysis of the following:

Types of findings within the backlog

Equipment types for the findings within the backlog

SCE analyzes trends with respect notification's problem statements because this directly affects the urgency with which an issue must be addressed. Additionally, SCE continues to assess whether problem statement individual scoring is appropriate based on recent trends in the field. These notification monitoring practices ensure that field personnel are aligned in their procedures to assign findings so that work can be accurately prioritized and timely corrected. Table SCE 8-05 and Table SCE 8-06 summarizes the primary findings identified within the backlog. As stated above, SCE prioritizes notifications based on both the severity of the findings and the HFRA location.

Table SCE 8-05: Types of findings within the backlog - distribution[142]

Type of Finding within the Backlog	Percentage of Finding within the Backlog	Equipment Type
Repair/Replace Pole	25%	Distribution Poles
Notify Customer (e.g., unauthorized attachments on poles)	23%	Distribution Poles
Repair/Replace Avian Protection or Remove Nest	11%	Distribution Poles, Transformers, Capacitors
Notify Communication Infrastructure Provider or Third Party	9%	Distribution Poles
Repair/Replace Hardware or Framing	6%	Distribution Poles, Transformers, Switches
Other	26%	Various

Table SCE 8-06: Types of findings within the backlog - transmission[143]

Type of Finding within the Backlog	Percentage of Finding within the Backlog	Equipment Type
Repair/Replace Pole	57%	Transmission Poles
Right of Way Issues	21%	Transmission Poles/Towers
Repair Hardware/Framing	8%	Transmission Poles/Towers
Repair Footing/Pedestal/Fence	3%	Transmission Tower
Repair Tower	2%	Transmission Tower
Other	9%	Various

Reinspection frequency for findings

As mentioned earlier, SCE's HFRI inspection frequency is based on HFRA Tier. SCE does not have a "reinspection" frequency per se. Assets with open notifications could be inspected again if the notification is still open during the next inspection as part of SCE's risk-informed HFRI schedule cadence.

Outcomes of reinspection, including changes to prioritization or expected due dates

SCE does not make changes to notifications based on reinspection per explanation on inspection frequency above. If the notification is still present at the time of a subsequent

142 This is a representative sample based on types of findings in the backlog as of 12/31/2024.
143 This is a representative sample based on types of findings in the backlog as of 12/31/2024.

inspection in line with the HFRI inspection frequency, the notification is confirmed. If the condition has significantly deteriorated and a higher priority notification is required based on GO 95 and internal guidelines, it would be created at that time.

Prioritization level within the backlog[144]

SCE's asset notifications are prioritized from highest to lowest as follows: Priority 1 (P1), Priority 2 (P2), and Priority 3 (P3). These align with Levels 1, 2, and 3 in GO 95 Rule 18(B)(1)(a). SCE does not change priority levels in the backlog, however, for aged P2 notifications, risk prioritization is applied to ensure that SCE is periodically reviewing and addressing the riskiest notifications that are not constrained due to GO 95 exceptions or third-party issues. By prioritizing the highest risk notifications, SCE is applying a risk-based approach to reducing open notifications as well as factoring the age of the notification, probability of ignition and other factors to determine ignition risk outlined below.

SCE considers several criteria to determine a notification's ignition risk to prioritize the notification backlog:

- Whether the location is within HFRA
- Wildfire consequence score (based on how many acres and structures would burn)
- AOC identifier – if the notification is on a structure that is within that year/season's AOC
- PSPS identifier – if the notification is on a circuit that could be activated for PSPS
- Compliance due date assigned depending on location of the notification
- Problem statement identifies the condition of the asset (i.e. Repair broken insulator)
- POI (probability of ignition of the equipment type)
- Age of the notification

In addition, each electrical corporation must provide an ageing report for work orders past due[145] *(Table 8-5 and Table 8-6 provide examples).*

Table 8-5: Number of Past Due Asset Work Orders Categorized by Age[146]

HFTD Area	0-30 Days	31-90 Days	91-180 Days	181+ Days	Total
Non-HFTD	183	510	555	8,100	9,348
HFTD Tier 2	30	216	502	1,196	1,944
HFTD Tier 3	844	1,130	925	2,074	4,973
Total	1,057	1,856	1,982	11,370	16,265

144 ECs must include the associated GO 95 Rule 18 level. If the EC uses a different prioritization level system, this must be included in addition to the GO 95 levels, with an explanation as to why the EC is using a different system.

145 A past due work order is any work order that remains open beyond the shorter of two timeframes: the one required by the electrical corporation, or the one required by GO 95.

146 This table includes data that was past due as of 12/31/24.

Table SCE 8-07: Ignition Risk Potential - Past Due Asset Notifications Categorized by Age[147]

HFTD Area	0-30 Days	31-90 Days	91-180 Days	181+ Days	Total
Non-HFTD	0	0	0	0	0
HFTD Tier 2	15	182	349	767	1,313
HFTD Tier 3	748	1,023	784	1,606	4,161
Total	763	1,205	1,133	2,373	5,474

Table 8-6: Number of Past Due Asset Work Orders Categorized by Age for Priority Levels[148]

Priority Level	**0-30 Days**	**31-90 Days**	**91-180 Days**	**181+ Days**	**Total**
Priority 1	0	0	0	0	0
Priority 2	960	1,467	1,377	11,292	15,096
Priority 3	97	389	605	78	1,169
Total	1,057	1,856	1,982	11,370	16,265

Table SCE 8-08: Ignition Risk Potential - Number of Past Due Asset Notifications Categorized by Age for Priority Levels[149]

Priority Level	0-30 Days	31-90 Days	91-180 Days	181+ Days	Total
Priority 1	0	0	0	0	0
Priority 2	763	1,205	1,133	2,373	5,474
Priority 3	0	0	0	0	0
Total	763	1,205	1,133	2,373	5,474

147 This table includes data that was past due as of 12/31/24.
148 This table includes data that was past due as of 12/31/24.
149 This table includes data that was past due as of 12/31/24.

8.7 Grid Operations and Procedures

8.7.1 Equipment Settings to Reduce Wildfire Risk

In this section, the electrical corporation must discuss the ways in which it operates its system to reduce wildfire risk.[74] *The equipment settings discussion must include the following:*

- *PEDS*
- *Automatic recloser settings*
- *Settings of other emerging technologies (e.g., rapid earth fault current limiters)*

For each of the above, the electrical corporation must provide a narrative that includes the following, as applicable:

- *Settings used to reduce wildfire risk.*
- *Analysis of reliability/safety impacts for settings the electrical corporation uses. This must include the following:*
  - *Analysis of the most impacted circuits, including how the electrical corporation determined which circuits were most impacted.*
  - *The total number of outages that have occurred on the most impacted circuits when settings were enabled.*
  - *The cumulative customer-minutes associated with outages on the most impacted circuits.*
  - *How the electrical corporation has worked to alleviate future reliability/safety impacts along the most impacted circuits.*
  - *Deenergization protocols must consider impact on critical first responders, health and communication infrastructure, and medical baseline customers.*
- *The impacts via tabular data for the top ten most impacted circuits/circuit segments from the previous three years, as shown in Table 8-7 below:*
- *Criteria for when the electrical corporation enables the settings.*
- *Operational procedures for when the settings are enabled, including monitoring for re-energization.*
- *The number of circuit miles capable of these settings, including the percentage of circuit miles in the HFTD and HFRA covered by these settings.*

- *The percentage of time settings were enabled for the past three years based on the amount of times enablement criteria thresholds were met and led to activation, and the associated number of circuit miles encompassed by activation at that time.*

- *An estimate of the effectiveness of the settings for reducing wildfire risk, including the calculation used for determining the effectiveness, a list of assumptions, and justification for these assumptions. The estimate must also include the number of ignitions that still occurred while sensitivity settings were enabled.*

8.7.1.1 PEDS

8.7.1.1.1 Settings to reduce wildfire risk

Fast Curve settings on circuit breakers and RARs are protective equipment and device settings (PEDS) that stop the flow of electricity when an electrical fault is detected on a line, such as from contact with vegetation. Fast Curves operate faster than traditional relay protection settings, reduce the amount of energy released at the fault location, and decrease the likelihood of a fault creating an arc or a sparking event that could result in an ignition. SCE first began installing Fast Curve settings in 2018. Please see related discussions of Fast Curves in Section 8.2.8.1 and Section 10.5.1.

SCE uses the term "enabled" to mean that Fast Curve settings have been installed and are active (i.e., they will trip upon detecting potential fault conditions). SCE notes that the terms "enabled" or "capable" should not be confused with terms like "installed" which means that a protection device has the necessary hardware and software to operate as a Fast Curve device.

SCE's intention with Fast Curve settings is to increase response speed to potential faults, but not to increase sensitivity. In other words, Fast Curve allows the grid to respond more safely and more quickly to the same triggering conditions that would have caused an outage if Fast Curve was not enabled. Conceptually, it is similar to improving the brakes on a car: the car still needs to stop if it approaches a stop sign, but improved brakes allow for a safer and more controlled stop.

SCE began installing wildfire-driven protection devices (e.g., fuses, circuit breakers, and reclosers) from approximately 2017 through the present, which resulted in increased sectionalization of SCE's circuits. Sectionalization provides the ability to limit outages to portions of a circuit and, in most cases, has provided a reliability benefit to customers. Along with related and complementary mitigations such as covered conductor, vegetation management, and asset inspections, protection devices that enable sectionalization collectively reduce the potential for faults that can cause outages.

Currently, SCE's analysis of the relevant data indicate that Fast Curve settings have not led to increased outage frequency. Theoretically, Fast Curve settings could increase the number of customers impacted by an outage if a Fast Curve-enabled recloser or circuit breaker trips more quickly than a downstream protection device like a fuse or other recloser between the fault and tripped device. SCE has accounted for this possibility in its calculation of risk from Fast Curve settings.

8.7.1.1.2 Analysis of reliability/safety impacts for settings the electrical corporation uses. This must include the following:

8.7.1.1.2.1 Analysis of the most impacted circuits, including how the electrical corporation determined which circuits were most impacted.

SCE has used the criteria specified in Table 8-7 to identify the most impacted circuits. It is populated with the top ten circuits with outages during which Fast Curve settings were enabled.

8.7.1.1.2.2 The total number of outages that have occurred on the most impacted circuits when settings were enabled.

Please see Table 8-7.

8.7.1.1.2.3 The cumulative customer-minutes associated with outages on the most impacted circuits.

Please see Table 8-7.

8.7.1.1.2.4 How the electrical corporation has to alleviate future reliability/safety impacts along the most impacted circuits

SCE attempts to coordinate Fast Curve settings so that the nearest device upstream of a fault operates before other upstream devices. This helps increase the chance that only the section of the circuit downstream of the protective device is interrupted from service while the rest of the circuit remains energized. For example, if a fault occurs downstream of a branch line fuse at the end of a circuit, the fuse should operate before the upstream recloser or circuit breaker, which would mean that only the section of the circuit downstream of the branch line fuse is interrupted from service. SCE reviews this type of coordination and deploys its Fast Curve settings accordingly based on the configuration of each circuit.

SCE also notes that wildfire mitigations such as covered conductor have significantly improved reliability, with fully covered circuits featuring approximately 60% fewer faults than fully bare circuits from 2019 through 2024.

SCE has benchmarked its Fast Curve setting practices with other utilities and found that SCE's Fast Curve settings operate comparable to other utilities while striking a balance between fast operation and reliable coordination with other protection devices.

8.7.1.1.2.5 Deenergization protocols must consider impact on critical first responders, health and communication infrastructure, and medical baseline customers.

Fast Curve is not a proactive de-energization in which SCE uses protocols to determine if power should be shut off. Fast Curve settings are a wildfire-specific variation of protection devices that exist throughout a utility service territory and are intended to function like a fuse panel in a residential home, tripping when a fault is detected.

That being stated, SCE offers assistance to critical facility and infrastructure customers who may require additional assistance and advanced planning to ensure resiliency and continuity during de-energizations. SCE conducts various outreach activities throughout the year. SCE also works collaboratively with local governments, first responders and essential service providers to provide awareness of de-energizations and to educate them on the importance of developing a resiliency plan that addresses backup power needs for facilities that provide critical life and safety functions. Many of these customers are required by law or industry standards to have backup generation in place to sustain critical operations in the event of a power outage, regardless of outage type. Other customers that are not required to have backup generation are still encouraged to consider adding this capability if they feel they have critical needs that must continue in a power outage. Medical Baseline customers receive additional program eligibility for SCE's Critical Care Backup Battery Program outlined in Section 11.5.1 if they reside in SCE's HFRA. This program supports customers' ability to utilize their medical equipment in the event of an outage.

8.7.1.1.3 The impacts via tabular data for the top ten most impacted circuits/circuit segments from the previous three years

SCE has populated Table 8-7 below, which shows outages when Fast Curve settings were enabled. SCE notes that these outages should not be interpreted as caused by Fast Curve, as in most cases they would have occurred regardless because the device detected fault conditions and responded appropriately. The primary difference is that Fast Curve settings can operate more rapidly, therefore reducing the potential for electrical energy release that creates an ignition risk.

Table 8-7: Top Ten Impacted Circuits from Changes to PEDS in the Past Three Years (2022-2024)

Circuit/ Circuit Segment ID	Circuit/ Circuit Segment Name	Circuit/ Circuit Segment Length (overhead circuit miles)	Number of outages in Past Three Years	Cumulative Outage Duration (hours)	Cumulative Number of Customers impacted by outages
ED-02827	CAMPANULA	127.65	43	89	19,325
ED-14646	RAISIN	11.37	18	165	26,673
ED-18094	TRAM	8.72	18	367	12
ED-16478	SKY HI	133.28	17	62	3,840
ED-03715	COACHELLA	21.27	14	46	33
ED-08946	INVADER	25.56	13	166	2,338
ED-14371	POTATO	15.34	13	194	16,408
ED-14038	PICKLE MEADOWS	25.99	12	95	967

Circuit/ Circuit Segment ID	Circuit/ Circuit Segment Name	Circuit/ Circuit Segment Length (overhead circuit miles)	Number of outages in Past Three Years	Cumulative Outage Duration (hours)	Cumulative Number of Customers impacted by outages
ED-00335	ALLVIEW	2.59	11	6	1,107
ED-04596	DALBA	7.96	11	6	2,388

8.7.1.1.4 Criteria for when the electrical corporation enables the settings

SCE enables Fast Curve settings during elevated fire conditions. The criteria for these conditions include Red Flag Warnings (RFW) declared by the NWS and/or a Fire Weather Threats (FWT), Fire Climate Zones (FCZ), Thunderstorm Threats (TT) or PSPS Proximity Threats declared by SCE's weather forecasting team. These criteria are outlined in SCE's Standard Operating Bulletin (SOB) 322 and has evolved based on lessons learned from historical conditions (e.g., addition of FCZ, TT, etc.). SOB 322 helps to ensure consistency in the execution of HFRA protocols by consolidating the protocols into one bulletin that is used to train key stakeholders. SOB 322 contains updated operational protocols and standards for the safe operation of HFRA circuits and guides SCE's response during wildfire events and PSPS operations to help mitigate and reduce wildfire ignitions.

The application of Fast Curve settings for the distribution system during a RFW, FCZ, FWT, TT, or PSPS proximity threat helps to ensure the electrical energy released during a fault is minimized during a time of high wildfire risk. Transmission and sub-transmission systems typically have high-speed tripping relays, so Fast Curve settings are not needed on these systems.

8.7.1.1.5 Operational procedures for when the settings are enabled, including monitoring for re-energization

SCE blocks automatic reclosing in conjunction with enabling Fast Curve settings to avoid re-energizing when a fault condition is still present during high fire conditions. Accordingly, following operation of a relay that has Fast Curve settings enabled, the impacted circuit is patrolled prior to re-energization, pursuant to SOB 322. This helps ensure that qualified personnel identify and mitigate any conditions that could potentially lead to a wildfire ignition upon re-energization.

8.7.1.1.6 The number of circuit miles capable of these settings, including the percentage of circuit miles in the HFTD and HFRA covered by these settings

All distribution HFRA miles are capable of Fast Curve settings.

8.7.1.1.7 The percentage of time settings were enabled for the past three years based on the amount of times enablement criteria thresholds were met and led to activation, and the associated number of circuit miles encompassed by activation at that time.

From 2022 through Q3 of 2024, Fast Curve settings were enabled 54% of the time on SCE's overhead lines within its HFRA. As noted above, all distribution miles in SCE's HFRA are capable of Fast Curve settings.

8.7.1.1.8 An estimate of the effectiveness of the settings for reducing wildfire risk, including the calculation used for determining the effectiveness, a list of assumptions, and justification for these assumptions. The estimate must also include the number of ignitions that still occurred while sensitivity settings were enabled.

SCE began using Fast Curve settings in 2018. In June 2022, SCE refined its settings for application to new and existing installations. Fast Curve is applied in conjunction with recloser relay blocking, which prevents the automatic closing of circuit breakers and RARs following a relay/trip operation. The combined effectiveness of Fast Curve and recloser relay blocking for the years 2021 to 2023 was estimated comparing ignition event frequencies of SCE circuits. Based on this analysis, SCE found an ignition reduction per fault of 41% in 2021, 18% in 2022, and 55% in 2023.

8.7.1.2 Automatic Recloser Settings

During normal operations, automatic reclosing devices that are installed on circuits will operate to re-energize (i.e., "re-close") the circuit after a fault event to quickly restore electric service to customers. Although this approach has many benefits for addressing faults that are temporary, if the fault persists (e.g., is permanent) and fire risk is present, then subsequent attempts to automatically re-energize the circuits through this process could lead to an ignition. SCE blocks RARs in areas and times of particular risk of an ignition. Blocking reclosing means that no attempted re-energization takes place automatically. SCE's current remote-control capabilities allow for blocking of reclosing relays for circuit breakers and RARs with group commands of hundreds of devices at once.

Recloser blocking is performed concurrently with the enabling of Fast Curve settings, and as such the recloser is operating based on protocols. Hence their effect is the same, and outages when Fast Curve was enabled will be the same as outages with recloser blocking.

8.7.1.2.1 Settings to reduce wildfire risk

8.7.1.2.2 Analysis of reliability/safety impacts for settings the electrical corporation uses. This must include the following:

8.7.1.2.2.1 Analysis of the most impacted circuits, including how the electrical corporation determined which circuits were most impacted.

Please see Table 8-7 above. As previously explained, this population is the same for both PEDS and for reclosers.

8.7.1.2.2.2 The total number of outages that have occurred on the most impacted circuits when settings were enabled.

Please see Table 8-7.

8.7.1.2.2.3 The cumulative customer-minutes associated with outages on the most impacted circuits

Please see Table 8-7.

8.7.1.2.2.4 How the electrical corporation has worked to alleviate future reliability/safety impacts along the most impacted circuits

As reclosers operate in response to detected fault conditions, SCE's primary focus on reducing potential customer impacts is through risk-prioritized asset inspections, vegetation management, and grid hardening mitigations such as covered conductor. All of those activities reduce the potential for the risk drivers that can lead to fault conditions, which in turn can lead to a recloser opening with a resulting loss of power. For example, vegetation management programs maintain clearances of vegetation from distribution lines, which reduces the potential for contact that would lead to a fault and potentially an outage.

8.7.1.2.2.5 Deenergization protocols must consider impact on critical first responders, health and communication infrastructure, and medical baseline customers

Please see the discussion above in Section 8.7.1.1.

8.7.1.2.3 The impacts via tabular data for the top ten most impacted circuits/circuit segments from the previous three years, as shown in Table 8-7 below:

Please see Table 8-7 above.

8.7.1.2.4 Criteria for when the electrical corporation enables the settings

Please see the discussion above in Section 8.7.1.1.

8.7.1.2.5 Operational procedures for when the settings are enabled

Please see the discussion above in Section 8.7.1.1.

8.7.1.2.6 The number of circuit miles capable of these settings, including the percentage of circuit miles in the HFTD and HFRA covered by these settings.

All HFRA miles are capable of blocking automatic reclosing of reclosers.

8.7.1.2.7 The percentage of time settings were enabled for the past three years based on the amount of times enablement criteria thresholds were met and led to activation, and the associated number of circuit miles encompassed by activation at that time.

Please see the discussion above in Section 8.7.1.1.

8.7.1.2.8 An estimate of the effectiveness of the settings for reducing wildfire risk, including the calculation used for determining the effectiveness, a list of assumptions, and justification for these assumptions. The estimate must also include the number of ignitions that still occurred while sensitivity settings were enabled.

Please see the discussion above in Section 8.7.1.1.

8.7.1.3 Settings of other emerging technologies (e.g. REFCL)

Please see Section 10.3 for SCE's discussion of several programs (i.e. REFCL, DOPD, TOPD, Hi-Z) that monitor for fault conditions.

Please also see related discussions of REFCL in Section 8.2.6 as well as in Section 10.3.

8.7.2 Grid Response Procedures and Notifications

The electrical corporation must provide a narrative on operational procedures it uses to respond to faults, ignitions, or other issues detected on its grid that may result in a wildfire including how the electrical corporation:

- *Locates the issues*
- *Prioritizes the issues, including how operational models inform potential prioritization based on risk*
- *Notifies relevant personnel and suppression resources to respond to issues*
- *Minimizes/optimizes response times to issues*

Locates the issues

Identification of issues detected on the grid can come from a number of sources, including analysis of meter data, HD cameras, customer calls, circuit patrols (including PSPS pre- and post-event patrols), and grid monitoring equipment.

Prioritize issues, including how operational models inform potential prioritization based on risk

Prioritization depends on severity of the issue and the circumstances of the event. For example, a fault in HFRA during a fire weather threat period may be prioritized over less potentially severe issues. Public safety issues (e.g., wire-down, 911 emergencies, etc.) are typically prioritized first, followed by reliability/significant customer issues, then power quality related (voltage problems, etc.) issues. However, prioritization of such matters would still depend on circumstances, including whether there is an immediate safety issue present, and are typically reviewed at our dispatch operations centers. SCE's SOB 322 also establishes procedures for patrolling and re-energizing during high-risk conditions.

For fires detected through SCE's HD cameras, SCE will map the location of the fire and conduct a fire threat assessment related to SCE's infrastructure. SCE will prioritize threats based on proximity to bulk power, distribution lines, generation facilities, and public assets at risk, as these will have the greatest downstream impacts to customers.

Notifies relevant personnel and suppression resources to respond to issues

In HFRA, SCE typically de-energizes and sends out a troubleman to patrol the entire line to find and address any damage prior to re-energization.

For an energized wire down detected by smart meters, such as through Meter Alarm Down Energized Conductor (MADEC), the alerts are sent to a switching center, which will take appropriate steps prior to de-energizing the line. For Primary Issue Alerts,[150] SCE sends a troubleman to investigate the issue.

Furthermore, for fires and other emergencies, SCE's Public Safety Partners are already integrated with the same HD camera networks and email alerts as SCE for fires in their areas. SCE works with responding fire agencies to coordinate emergency response, damage assessment, and electrical service restoration.

SCE's HFRA Fire Prevention and Hot Work Restrictions (HFRA-1) establishes the procedure for all SCE field operating organizations to always remain vigilant and alert for fires or possible fires while working or traveling in HFRA. Any identified fires are immediately reported to 911 and the appropriate Switching Center or Control Center as soon as possible.

Minimizes/optimizes response times to issues

SCE works to ensure that enough troublemen are assigned to cover each area to lower response times. This may include, for example, assigning more troublemen to report to districts with a higher frequency of events and obtaining additional resources when needed

150 Primary Issues Alerts are system-generated alerts that notify SCE's grid operations about possible primary issues based on meter exception data and SCE connectivity information.

(e.g., from adjacent sectors or from other personnel). For wire-downs, SCE typically measures the response time from the time of the call to the time of arrival at the location.

Circuit patrols also carry some limited fire suppression resources in case of sparks or ignitions discovered during a patrol performed pursuant to SOB 322.

For fires, SCE has a 24-7 Watch Office that monitors fires and coordinates with SCE's Grid Control Center to advise of any fire threats to the bulk power system. SCE's Fire Management organization will also reach out to the troublemen at the affected District(s) to provide liaison support, such as coordination for potential de-energizations and to provide detailed information about the fire.

8.7.3 Personnel Work Procedures and Training in Conditions of Elevated Fire Risk

The electrical corporation must provide a narrative on the following:

- *The electrical corporation's procedures that designate what type of work the electrical corporation allows (or does not allow) personnel to perform during operating conditions of different levels of wildfire risk, including:*
    - *What the electrical corporation allows (or does not allow) during each level of risk*
    - *How the electrical corporation defines each level of wildfire risk*
    - *How the electrical corporation trains its personnel on those procedures*
    - *How it notifies personnel when conditions change, warranting implementation of those procedures*
- *The electrical corporation's procedures for deployment of firefighting staff and equipment (e.g., fire suppression engines, hoses, water tenders, etc.) to worksites for site-specific fire prevention and ignition mitigation during on-site work.*

What the electrical corporation allows (or does not allow) during each level of risk

SCE has implemented work procedures that outline the necessary steps to mitigate ignitions associated with crews and equipment in HFRA and empower qualified employees to request temporary de-energization of a line or line segment. These procedures also contain provisions that restrict or delay field work when conditions call for such action. Non-emergency/routine work involving hot work activities shall be cancelled when working on or near circuits that have been or may be de-energized due to a PSPS event. SCE employees and contractors are required to follow all of the fire mitigation practices whenever conducting hot work activities. SCE also provides these employees with the training necessary to safely perform these activities and ensures that their contractors are aware of their obligation to train their crews of these procedures and program.

All personnel responses to issues on the grid are subject to SOB 322 operating restrictions in HFRA and PSPS Outages and are coordinated in multiple control and monitoring systems, such as SCE's Energy Management System, Distribution Management System, and Grid Management System.

How the electrical corporation defines each level of wildfire risk

The HFRA Hot Work Restriction and Mitigation Measures program applies to both SCE employees and contractors and is intended to reduce their risk of causing an ignition during the normal course of work in HFRA when the weather and fuel conditions are more susceptible to fire ignitions. SCE uses the Fire Weather Threat Report to identify circuits that are forecast to meet or exceed designated thresholds for Operating Restrictions. This list also identifies counties that are under a Red Flag Warning and highlights the affected Switching Centers. SCE Weather Services publishes Fire Weather Reports daily as conditions warrant.

How the electrical corporation trains its personnel on those procedures

SCE provides annual training to all field personnel (employees and contractors) performing wildfire mitigation activities, patrols, and live field observations. The training includes PSPS Operating Protocols, PSPS Decision-Making Tool Enhancements, Patrolling and Live Field Observation for field operations, and Field Operation Tool Training. This training will be refreshed for all field personnel performing the same types of patrols in 2026, which includes both experienced and new resources.

SCE will continue to provide training to field personnel prior to every wildfire season, as additional resources are onboarded every year that need to be trained. The annual training will include updates to all SOBs and any updates in work restriction procedures. SCE continues to refine its training program based on feedback from field employees and its QC program.

How it notifies personnel when conditions change, warranting implementation of those procedures

Before the start of each job, or in the event the scope of the job changes, every supervisor/job lead will assemble his/her crew and outline the proper work procedures/methods, roles and responsibilities, and possible hazards in order to conduct the work safely and minimize the risk of an ignition.

If there are changes to the forecast and circuits are added to the PSPS monitoring list with a period of concern that is concurrent to hot work activities being performed, work is safely stopped. Any exceptions are requested to the PSPS Incident Management Team incident commander for review and approval along with the appropriate justifications and described mitigations.

The electrical corporation's procedures for deployment of firefighting staff and equipment (e.g., fire suppression engines, hoses, water tenders, etc.) to worksites for site-specific fire prevention and ignition mitigation during on-site work.

SCE's HFRA Hot Work Restriction and Mitigation Measures Program contains provisions to mitigate crew-caused ignitions and are in effect whenever performing hot work activities in SCE's HFRAs, with limited exceptions. The program requires SCE and contract crews performing hot work activities to be equipped with basic fire mitigation and suppression tools with the goal of preventing ignitions and rapidly responding to incipient stage ignitions should one occur during the normal course of their work in the field. For example, all combustibles are relocated/swept clean of at least 35 feet in all directions from the Hot Work Area. A minimum 10-feet radius must be cleared of mineral earth/dirt or sprayed with water and reapplied as needed to remain damp throughout the duration of hot work. If relocation is impractical, combustibles must be protected by a listed or approved Welding Blanket, Welding Pad, or equivalent. A welding tent, fire/blast/arc blankets, and/or metal shield surrounding the hot work must be deployed. Fire-resistant tarps may also be suspended beneath work.

SCE performed benchmarking studies regarding dedicated fire suppression resources and services with other utility companies and determined that the number and size of ignitions first encountered by field crews did not support pursuing professional, private firefighting resources. SCE will continue using its existing HFRA Hot Work Restriction and Mitigation Program and related protocols to help prevent crew- or equipment-caused ignitions, and in the event of an ignition, the crews will use their equipment, such as fire extinguishers, shovels, and/or heavy-duty metal rakes, and a completely filled water backpack to put out incipient stage fires that could occur during the course of their activities in the field. SCE will also continue to monitor the risks posed by ignitions first encountered by its field crews and consider professional firefighting crews as an option in future iterations of its WMP.

8.8 Workforce Planning

In this section, the electrical corporation must provide an overview of personnel, including qualifications, and training practices, related to workers in roles associated with asset inspections, grid hardening, and risk event inspection.

Asset Inspections

Personnel involved in asset inspections are required to have a comprehensive understanding of electrical systems and inspection protocols. The qualifications for these roles include knowledge of basic electricity and electrical distribution principles. See Table SCE 8-09 worker titles and special certifications required for asset inspections.

Training practices for asset inspections include a comprehensive training program for new Electrical System Inspectors (ESIs), which covers new processes, procedures, and lessons learned relevant to inspection practices. This program focuses on improving inspection quality and ensuring consistent inspection results. Additionally, SCE implements technical training for those performing inspections to prepare workers to perform their jobs safely, comply with regulatory requirements and laws, maintain system reliability, and meet the demands of new technology. Worker qualifications and training for Asset Inspections will evolve and adapt in accordance with any future changes to our inspection programs, designs, and operational practices.

Grid Hardening

Personnel involved in grid hardening are required to have knowledge of applicable SCE standards, policies and procedures, GO 95/128, electrical theory and mechanical principles. See Table SCE 8-09 worker titles and special certifications required for grid hardening.

To facilitate grid hardening work, SCE implements training for SCE workers that includes core technical training for working on the electric system, as well as specialized training on PSPS, HFRA, grid hardening, etc., and prepares workers to perform their jobs safely, comply with regulatory requirements and laws, maintain system reliability, and meet the demands of new technology. Wildfire activities may also require the use of new technology, such as situational awareness tools or information technology. The use of new technology is usually accompanied by end-user training to help ensure the appropriate click-through of the application and accurate capture of data.

Risk Event Inspection

SCE inspects various risk events (e.g., ignitions, outages, wire-down, faults, etc.) to determine cause and to remediate issues. See Table SCE 8-09 worker titles and special certifications required for risk event inspection.

The scope of risk event inspections includes identifying hazards that could lead to safety and reliability issues and implementing corrective actions to mitigate these risks. SCE conducts training for workers in the Risk Event Inspection role related to its wildfire mitigation and PSPS work.

Table SCE 8-09: Personnel Qualifications and Training for Asset Inspections, Grid Hardening and Risk Event Inspections

Worker Title	Special Certification Requirements	Target Role(s)
Electrical System Inspector	N/A	Asset Inspections
Journeyman Transmission/Distribution Lineman	QEW	Asset Inspections, Grid Hardening, Risk Event Inspections
Patrolman	QEW	Asset Inspections, Risk Event Inspections
Helicopter Pilot	FAA Certified	Asset Inspections
Sensor Operator	N/A	Asset Inspections
Generation: Technician, Hydro Electrician & Instrument Control /ICE Technician	QEW	Asset Inspections, Grid Hardening
Generation: Hydro Foreman Electrician & Instrument Control Technician /Foreman, ICE Technician	QEW	Asset Inspections, Grid Hardening
Generation: Operator, Chief Hydro Station	N/A	Asset Inspections
Generation: Hydro Operator Mechanic /Plant Equipment Operator	N/A	Asset Inspections, Grid Hardening
Unmanned Aircraft Systems (UAS) Pilot	FAA Certified	Asset Inspections
UAS Observer	N/A	Asset Inspections
Infrared Thermographer	N/A	Asset Inspections
Infrared General Manager Thermographer	Infrared Thermographer Level III	Asset Inspections
Aerial Desktop Foreman	QEW	Asset Inspections
Transmission/Distribution Apprentice Lineman	N/A	Grid Hardening, Risk Event Inspections
Foreman	QEW	Grid Hardening, Risk Event Inspections
Groundman	N/A	Grid Hardening, Risk Event Inspections
Splicer	QEW	Grid Hardening, Risk Event Inspections

Worker Title	Special Certification Requirements	Target Role(s)
Substation Maintenance Electrician	QEW	Grid Hardening
Test Technician	QEW	Grid Hardening
Apparatus Technician	QEW	Risk Event Inspections
Troubleman	QEW	Risk Event Inspections
FIPA Engineer	N/A	Risk Event Inspections

9 VEGETATION MANAGEMENT AND INSPECTIONS

Each electrical corporation's WMP must include plans for vegetation management.

9.1 Targets

In this section, the electrical corporation must provide qualitative and quantitative targets for vegetation management and inspections for each year of the three-year WMP cycle. The electrical corporation must provide at least one qualitative or quantitative target for the following initiatives:

- *Wood and Slash Management (Section 9.5)*
- *Defensible Space (Section 9.6)*
- *Integrated Vegetation Management (Section 9.7)*
- *Workforce Planning (Section 9.13)*

Quantitative targets are required for vegetation management inspections and pole clearing; see Section 9.1.2, below, for detailed requirements.

Quantitative targets are required for QA and QC. See Section 9.11.1 for detailed quantitative target requirements for QA and QC. Reporting of QA and QC quantitative targets is only required in section 9.11.

9.1.1 Qualitative Targets

The electrical corporation must provide qualitative targets for implementing and improving its vegetation management and inspections, including the following:

- *Identification of which initiative(s) and activity/activities in the WMP the electrical corporation is implementing to achieve the stated target, including Tracking IDs and the Tracking ID(s) used in past WMPs ("Previous Tracking ID"), if applicable*
- *A completion date for when the electrical corporation will achieve the qualitative target*
- *Reference(s) to the WMP section(s) or appendix, including page numbers, where the details of the target(s) are documented and substantiated*

This information must be provided in Table 9-1 below.

9.1.2 Quantitative Targets

The electrical corporation must provide quantitative targets it will use to track progress on its vegetation management and inspections for the three years of the Base WMP. Every inspection activity (program) described in Section 9.2 must have at least one quantitative target. Targets for inspection activities (programs) of overhead electrical assets must use circuit miles as the unit. Pole clearing performed in compliance with Public Resources Code section 4292 must have a quantitative target. The electrical corporation may define additional pole clearing targets (e.g., pole clearing performing in the Local Responsibility Area). For each quantitative target, the electrical corporation must provide the following:

- *Identification of which initiative(s) and activity/activities in the WMP the electrical corporation is implementing to achieve the stated target, including Tracking IDs and the Tracking ID(s) used in past WMPs ("Previous Tracking ID"), if applicable.*
- *Projected targets and totals for each of the three years of the WMP cycle, e.g., [Year 1] end of year total, [Year 2] total, and [Year 3] total, three-year total and the associated units for the targets*
- *For inspections and pole clearing targets in Table 9-2, cumulative quarterly targets for each year of the WMP cycle*[151] *and the percentage of total overhead circuit miles in the HFTD covered by the [Year 1] target (e.g., 100 circuit miles of patrol inspections in [Year 1] divided by 300 overhead circuit miles in the HFTD equals 33 percent coverage*
- *The expected % risk reduction for each of the three years of the WMP cycle.*[152]
- *The timeline in which clearance and removal work prescribed by the inspection activity (program) will be completed (inspections and pole clearing only).*

Table 9-1 and Table 9-2 provide examples of the minimum acceptable level of information and required template.

151 Guidelines for WMP Update will provide additional instructions on future quarterly rolling target reporting.

152 The expected % risk reduction is the expected percentage risk reduction per year, as described in Section 6.2.1.2.

Table 9-1: SCE Vegetation Management Targets by Year (Non-inspection Targets)

Initiative	Quantitative or Qualitative Target	Activity (Tracking ID)	Previous Tracking ID, if applicable	Target Unit	2026 Target / Status [1]	% Risk Reduction for 2026	2027 Target / Status [1]	% Risk Reduction for 2027	2028 Target / Status [1]	% Risk Reduction 2028	Three-year Total	Section; Page Number
9.5 Wood and Slash Management	Qualitative	Wood and Slash Contractor Management (VM-11)	N/A	N/A	Implement Work Management System mandatory fields to document the removal method for all wood and slash (debris) and implement mandatory QC fields for sample-based verification	N/A	Monitor and develop reporting capability to document completion of wood and slash management activities	N/A	Continue to monitor wood and slash management activities and identify updates to wood and slash management practices, where applicable	N/A	N/A	9.5; p. 351
9.6 Defensible Space	Qualitative	Expanded Clearances for Non-Energized Facilities (VM-14)	N/A	N/A	Implement field inspections of non-energized water conveyance facilities and develop an expanded clearance treatment scope that can be implemented in 2027 and 2028	N/A	Begin expanded clearance treatments along non-energized water conveyance facilities	N/A	Continue expanded clearance treatments along non-energized water conveyance facilities	N/A	N/A	9.6; p. 352
9.7 Integrated Vegetation Management	Qualitative	VM Treatment Methodologies (VM-13)	N/A	N/A	Continue to evaluate and expand treatment methodologies across required vegetation management activities	N/A	Apply identified treatment methodologies across required vegetation management activities, contingent on prior year learning, and subject to environmental approval	N/A	Apply identified treatment methodologies across required vegetation management activities, contingent on prior year learning, and subject to environmental approval	N/A	N/A	9.7; p. 353
9.13 Workforce Planning	Qualitative	SCE VM Workforce Training (VM-12)	N/A	N/A	Continue partnership with educational institutes for SCE personnel to participate in professional seminars and webinars	N/A	Continue partnership with educational institutes for SCE personnel to participate in professional seminars and webinars	N/A	Continue partnership with educational institutes for SCE personnel to participate in professional seminars and webinars	N/A	N/A	9.13; p.376
9.2 Vegetation Management Inspections	Qualitative	Transition from Ground-based Inspections to Remote Sensing to Perform a Portion of Inspections for Clearances from Distribution Lines (VM-15)	N/A	N/A	Build core capabilities (crown segmentation and trim prescription) for Distribution to implement remote inspections and work prescription.	N/A	Begin operationalization and evaluation of remote sensing effectiveness for Distribution ground inspection reductions.	N/A	Deploy remote sensing where applicable and determine ground inspection reduction based on proven effectiveness of technology.	N/A	N/A	9.2; p. 336

Initiative	Quantitative or Qualitative Target	Activity (Tracking ID)	Previous Tracking ID, if applicable	Target Unit	2026 Target / Status [1]	% Risk Reduction for 2026	2027 Target / Status [1]	% Risk Reduction for 2027	2028 Target / Status [1]	% Risk Reduction 2028	Three-year Total	Section; Page Number
9.2 Vegetation Management Inspections	Qualitative	Transition from Ground-based Inspections to Remote Sensing to Perform a Portion of Inspections for Clearances from Transmission Lines (VM-16)	N/A	N/A	Begin operationalization and evaluation of remote sensing effectiveness for Transmission ground inspection reductions.	N/A	Deploy remote sensing where applicable and determine ground inspection reduction based on proven effectiveness of technology.	N/A	Evaluate and identify opportunities to increase effectiveness of technology by leveraging machine learning models.	N/A	N/A	9.2; p. 336
9.2 Vegetation Management Inspections	Qualitative	Effectiveness of Remote Sensing Pilot – Distribution (VM-17)	N/A	N/A	Produce metrics for Distribution ground and remote sensing inspection efficacy	N/A	N/A – Remote Sensing Pilot is scheduled to be completed in 2026.	N/A	N/A – Remote Sensing Pilot is scheduled to be completed in 2026.	N/A	N/A	9.2; p. 336
9.2 Vegetation Management Inspections	Qualitative	Effectiveness of Remote Sensing Pilot – Transmission (VM-18)	N/A	N/A	Produce metrics for Transmission ground and remote sensing inspection efficacy	N/A	N/A – Remote Sensing Pilot is scheduled to be completed in 2026.	N/A	N/A – Remote Sensing Pilot is scheduled to be completed in 2026.	N/A	N/A	9.2; p. 336

[1] The completion date for all qualitative targets is December 31, unless otherwise specified.

Table 9-2: SCE Vegetation Inspections and Pole Clearing Targets by Year

Activity (Program)	Tracking ID	Previous Tracking ID, if applicable	Target Unit	Cumulative (Cml.) Quarterly Target 2026, Q1	Cml. Quarterly Target 2026, Q2	Cml. Quarterly Target 2026, Q3	Cml. Quarterly Target 2026, Q4	Cml. Quarterly Target 2027, Q1	Cml. Quarterly Target 2027, Q2	Cml. Quarterly Target 2027, Q3	Cml. Quarterly Target 2027, Q4	Cml. Quarterly Target 2028, Q1	Cml. Quarterly Target 2028, Q2	Cml. Quarterly Target 2028, Q3	Cml. Quarterly Target 2028, Q4	% HFTD covered in 2026	% Risk Reduction for 2026	% Risk reduction for 2027	% Risk reduction for 2028	Three-year Total	Activity Timeline Target	Section; Page Number
9.2 Vegetation Management Inspections	Hazard Tree Management Program (VM-1)	VM-1	Circuit Miles Inspected	1,040	2,600	4,300	Inspect 5,300 circuit miles and prescribe mitigation for hazardous trees with strike potential within SCE's HFRA	1,040	2,600	4,300	Inspect 5,300 circuit miles and prescribe mitigation for hazardous trees with strike potential within SCE's HFRA.	1,040	2,600	4,300	Inspect 5,300 circuit miles and prescribe mitigation for hazardous trees with strike potential within SCE's HFRA.	57%	0.04%	0.04%	0.04%	15,900	P1 within 72 hours [2] P2 and all other prescriptions within 30-180 days	9.2; p.336
9.2 Vegetation Management Inspections	Dead and Dying Tree Removal (VM-4)	VM-4	Circuit Miles Inspected	1,000	2,800	4,900	Inspect 6,100 circuit miles and prescribe mitigation for dead and dying trees with strike potential within SCE's HFRA	1,000	2,800	4,900	Inspect 6,100 circuit miles and prescribe mitigation for dead and dying trees with strike potential within SCE's HFRA	1,000	2,800	4,900	Inspect 6,100 circuit miles and prescribe mitigation for dead and dying trees with strike potential within SCE's HFRA	65%	0.06%	0.05%	0.05%	18,300	P1 within 72 hours P2 and all other prescriptions within 30-180 days	9.2; p. 336
9.2 Vegetation Management Inspections	Inspections for Vegetation Clearance from Distribution Lines (VM-7)	VM-7	Circuit Miles Inspected	17%	44%	72%	Inspect 100% of distribution circuit miles in HFRA and prescribe mitigation as needed to achieve clearance	17%	44%	72%	Inspect 100% of distribution circuit miles in HFRA and prescribe mitigation as needed to achieve clearance	17%	44%	72%	Inspect 100% of distribution circuit miles in HFRA and prescribe mitigation as needed to achieve clearance	100%	1.74%	1.69%	1.66%	100% annually	P1 within 24 hours [3] P2 and all other prescriptions within 30-180 days	9.2; p. 336
9.2 Vegetation Management Inspections	Inspections for Vegetation Clearance from Transmission Lines (VM-8)	VM-8	Circuit Miles Inspected	4%	49%	83%	Inspect 100% of Transmission circuit miles in HFRA and prescribe mitigation as needed to achieve clearance	4%	49%	83%	Inspect 100% of Transmission circuit miles in HFRA and prescribe mitigation as needed to achieve clearance	4%	49%	83%	Inspect 100% of Transmission circuit miles in HFRA and prescribe mitigation as needed to achieve clearance	100%	0.38%	0.38%	0.38%	100% annually	P1 within 24 hours P2 and all other prescriptions within 30-180 days	9.2; p. 336
9.4 Pole Clearing	Additional Structure Brushing (VM-2.1)	VM-2	Inspected Structures	7,319	58,554	117,108	Inspect 135,000 structures and perform clearance where necessary	7,319	58,554	117,108	Inspect 135,000 structures and perform clearance where necessary	7,319	58,554	117,108	Inspect 135,000 structures and perform clearance where necessary	44%	4.03%	4.00%	3.95%	405,000	Within 12 months	9.4; p.349
9.4 Pole Clearing	Compliance Structure Brushing (VM-2.2)	N/A	Inspected Structures	22,738	45,475	64,423	Inspect 73,000 structures and perform clearance where necessary and feasible	22,738	45,475	64,423	Inspect 73,000 structures and perform clearance where necessary and feasible	22,738	45,475	64,423	Inspect 73,000 structures and perform clearance where necessary and feasible	18%	6.26%	6.23%	6.24%	219,000	Within 12 months	9.4; p. 349

[2] When remediations are not system auto-assigned to tree trimmers, VM targets to assign work within 5 days of condition identification.
[3] In HFRA only, P1 conditions for vegetation within 18” and no prior evidence of contact shall be remediated within 72 hours.

9.2 Vegetation Management Inspections

In this section, the electrical corporation must provide an overview of its vegetation management inspection activities (programs) for overhead electrical assets. This section must not include pole clearing activities or defensible space activities around substations; see Section 9.4 for pole clearing and Section 9.6 for defensible space activities around substations.

The electrical corporation must first summarize details regarding its vegetation management inspections for overhead electrical assets in Table 9-3. The table must include the following:

- ***Type of inspection**: distribution or transmission*
- ***Inspection program name**: Identify various inspection activities (programs) within the electrical corporation (e.g., routine, enhanced vegetation, off-cycle)*
- ***Area inspected**: Identify the area that the inspection activity (program) covers (e.g., Service territory, HFTD only, Areas of Concern, etc.)*
- ***Frequency**: Identify the frequency of the inspection (e.g., annual, quarterly, three-year cycle)*

Table 9-3: Vegetation Management Inspection Frequency, Method, and Criteria

Type	Inspection Activity (Program)	Area Inspected	Frequency
Distribution	Inspections for Vegetation Clearances from Distribution Lines (VM-7)	Service Territory	Annually
Transmission	Inspections for Vegetation Clearances from Transmission Lines (VM-8)	Service Territory	Annually
Distribution	Hazard Tree Management Program (VM-1)	HFRA only	Annually or once every three years[153]
Distribution	Dead and Dying Tree Management Program (VM-4)	HFRA only	Annually

153 Based on their Tree Risk Index (TRI) score, the highest risk category A follows an annual cycle for HTMP inspections, while categories B, C, and D follow a three-year inspection cycle for HTMP.

The electrical corporation must then provide a narrative overview of each vegetation inspection activity (program) identified in Table 9-3. Section 9.2.1 provides instructions for the overviews. The sections must be numbered Section 9.2.1 to Section 9.2.n (i.e., each vegetation inspection activity [program] is detailed in its own section) with the name of the inspection activity (program) as the section title. The electrical corporation must include inspection activities (programs) it is discontinuing, has discontinued since the last WMP submission, or has consolidated into another activity (program), and explain why it is discontinuing or has discontinued the activity (program).

9.2.1 Inspections for Vegetation Clearances from Distribution Lines (VM-7)

9.2.1.1 Overview and Area Inspected

In this section, the electrical corporation must provide an overview of the inspection (activity) program. This overview must describe where the electrical corporation performs the inspection activities (programs) (e.g., Service Territory, HFTD only, Areas of Concern, etc.)

Inspections for vegetation clearances from distribution lines aim to prevent vegetation from encroaching upon distribution assets, thereby maintaining system reliability and reducing wildfire risk. These inspections are currently ground and/or remote sensing[154] based and conducted throughout SCE's service territory.

Distribution circuit miles are inspected by ground patrols and/or remote sensing. SCE has incorporated expanded clearances into its routine inspection scope and utilizes the Grid Resiliency Clearance Distance (GRCD), as defined in 9.2.1.3, to verify whether an expanded clearance has been obtained. Ground-based inspections are expected to decrease and be supplemented by remote sensing technology as the technology matures.

9.2.1.2 Procedures

In this section, the electrical corporation must list the procedures, including the version(s) and effective date(s), for the inspection activity (program).

SCE's procedures for VM-7 are documented in its Distribution Vegetation Management Plan (UVM-03), Version 6, effective date April 1, 2024; LiDAR Schedule Reference Guide (UVM-06), Version 2, effective date May 17, 2019; and Inspection Manual UVM-09, Version 7, effective date June 30, 2024.

9.2.1.3 Clearance

In this section, the electrical corporation must describe how clearances are determined and prescribed through this inspection activity (program) (e.g., GO 95 Table 1, GO 95 Appendix E, ANSI A- 300, etc.). As applicable, the electrical corporation must describe how it differently prescribes clearances for high-risk species of vegetation.

154 Remote sensing methods include aerial, LiDAR and/or satellite.

SCE uses the GRCD to determine clearances from distribution lines which are based on standards set forth in GO 95 Rule 35 (Case 13 and Case 14), GO 95 Rule 37, PRC 4293, PRC 4292 Title 14 CCR Sections 1250-1258, and SCE's internal procedures UVM-03 and UVM-09. SCE strives to obtain expanded clearances of 12 feet or greater for distribution lines in HFRA. At a minimum, SCE's Inspections for Vegetation Clearances from Distribution Lines maintains at least the required four feet clearance for distribution lines within HFRA. Vegetation Inspections assess whether the vegetation meets these clearance requirements and prescribe corrective actions if necessary.

Certain tree species, due to their characteristics, have the potential to cause "grow-in" or "blow-in" incidents that could lead to an outage or an ignition. SCE manages high-risk species of vegetation and implements clearances, where possible, to reduce the probability of vegetation contacting electric facilities by providing species-specific categorization to its workforce to make appropriate work prescriptions.

Fast-growing species are typically pruned to maintain compliance for annual cycles. If the tree is not expected to maintain the compliance clearance distance (which is SCE's internal clearance target), for one year, a removal is typically pursued.

As an example, palms drive a significant number of off-cycle trims and emergency work required to prevent circuit interruptions and other safety risks. While the overall inventory of palms is low, historically palms have accounted for a significant portion of the Tree Caused Circuit Interruptions (TCCIs). To further mitigate public and worker safety risks associated with trimming palm trees, palms near lines are typically targeted for removal. Similarly, bamboo is one of the fastest growing plant species and SCE's preferred method is to remove it when possible.

9.2.1.4 Fall-in Mitigation

In this section, the electrical corporation must describe how it identifies fall-in risks, such as hazard trees, during the inspection (e.g., Level 1, Level 2, etc.). As applicable, the electrical corporation must of describe how it differently prescribes removal of high-risk species of vegetation.

Fall-in mitigation is primarily addressed through SCE's Hazard Tree and Dead and Dying Tree Programs. Please refer to Sections 9.2.3.4 and 9.2.4.4.

9.2.1.5 Scheduling

In this section, the electrical corporation must describe how the inspection activity (program) is scheduled. This must include the frequency (e.g., annual, quarterly, three-year cycle) and/or triggers (e.g., severe weather events, risk model outputs) of the inspection activity (program). It must also identify how the frequency and/or trigger might differ by HFTD tier or other risk designation.

If the inspection activity (program) is based on a fixed frequency (e.g., annual, three-year cycle), the electrical corporation must explain how it uses risk prioritization in the scheduling of the inspection activity (program) to target high-risk areas). If the electrical corporation does not use risk prioritization in the scheduling of the inspection activity (program), it must explain why.

Inspections for vegetation clearances from distribution lines are scheduled and conducted on an annual basis. The timing and scheduling of inspections may be adjusted in Areas of Concern (AOC) based on weather data, risk models, and environmental conditions. AOC are areas that pose increased fuel-driven and wind-driven fire risk. AOCs are identified based on several factors, including fire history, current and near-term fuel and weather conditions, vegetation type and amount, and impact to communities and SCE infrastructure. To mitigate the potential risk in AOC, SCE may adjust its vegetation inspection schedules to address risk in AOC.[155]

SCE targets annual vegetation inspections for all HFRA distribution circuit miles. Completion of this scope may be constrained by environmental conditions and risk prioritization efforts. Circuit mileage totals are dynamic and may shift due to HFRA boundary changes, GIS and data refinements, and asset-related adjustments such as conductor span length variations due to asset removal or installation.

9.2.1.6 Updates

In this section, the electrical corporation must discuss changes/updates to the inspection activity (program) since its last WMP submission, including known future plans (beyond the current year) and new/novel strategies the electrical corporation may implement in the next five years (e.g., references to and strategies from pilot projects and research). The electrical corporation must include lessons learned as applicable.

In 2024, SCE continued its implementation of a consolidated inspection strategy to improve contractor management, optimize work scheduling, support the transition from grid-based to circuit-based inspections, and enable increased use of remote sensing. This involves requiring Pre-Inspection contractors to perform inspection across all three vegetation management programs: Routine Line Clearing,[156] Hazard Tree Management Program, and Dead and Dying Tree Removal. As part of the consolidated inspection strategy, SCE started the transition from a grid-based inspection strategy (Vegetation Management grids are SCE-defined geographic boundaries that define a work area) to a more linear circuit-based inspection strategy. Shifting to a circuit-based inspection approach allows for alignment with other company initiatives, such as remote sensing to enable near real- time data capture.

In this 2026-2028 WMP, SCE is combining two prior WMP activities – expanded clearances for distribution lines (VM-7) and remote sensing distribution inspections (VM-9) – into a single WMP activity called “Inspections for Vegetation Clearance from Distribution Lines” (new VM-7). It is beneficial to combine the remote sensing and ground inspections because SCE plans to augment VM-7 by increasing the use of remote sensing technologies in its inspections. This shift will facilitate the transition from ground-based inspections to more remote sensing methodologies, thus providing valuable data for predictive models.

In 2025 and beyond, SCE plans to introduce the use of CanopySense, a suite of technology tools to aid in performing vegetation management inspection activities around distribution and transmission assets. CanopySense is a cloud-based platform that utilizes LiDAR or imagery (*e.g.,* satellite, orthoimagery) to determine vegetation encroachment to SCE’s circuit lines.

SCE‘s CanopySense project has completed two proofs of concept, Crown Segmentation

155 AOCs do not provide a comprehensive list of every area that could potentially have a major wildfire as this is not conceivable. AOCs concentrate on the more obvious locations where major wildfires could occur.

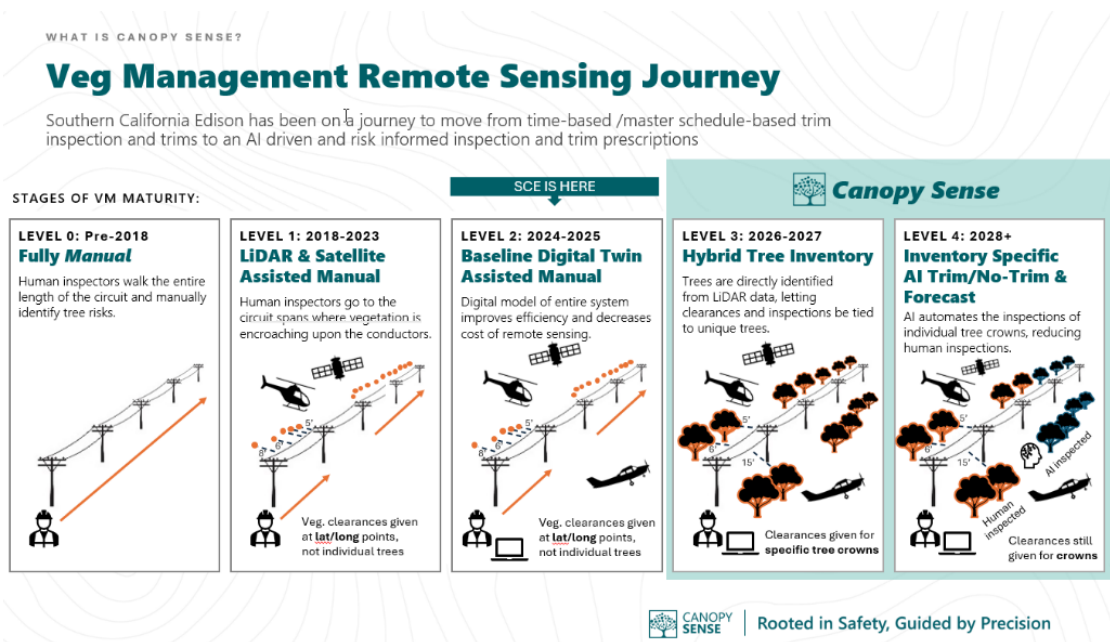
156 SCE refers to the inspections for vegetation clearances from distribution lines (VM-7) and transmission lines (VM-8) as Routine Line Clearing (RLC). Both programs are collectively termed Routine Line Clearing.

and TrimRx (Trim Prescription). These two solutions use remote sensing data (typically LiDAR) to determine vegetation location and clearance for Vegetation Management purposes. Crown segmentation is being used to identify, with high accuracy, the location of vegetation around overhead lines and then match those with historical tree inventory records. The imagery-defined tree canopy (crown) records will be reimaged in future years to provide ongoing data for tree growth and diminution. The TrimRx (Trim Prescription) technology is being used to auto-define tree work prescriptions based on clearance measurements. TrimRx will evolve over time and integrate other factors such as tree growth rates and seasonal weather patterns to better calibrate the auto-defined prescription.

Both solutions are being field validated by quality control personnel during 2025 and the beginning of 2026. Pending satisfactory results, SCE plans to pilot the new CanopySense technology on an incremental basis starting in 2026. SCE plans to use the new technology across the entire service area, which includes inspections for VM-7 and VM-8. For 2026 and beyond, the percentage of remote sensing supplementing ground inspections will be determined based on the results of the pilot. From 2026 to 2028, subject to the results of the remote sensing pilot, SCE plans to continue to use ground-based inspections in areas where remote sensing is unable to perform quality inventory inspections. Additionally, ground inspections will continue to be used for VM-1 (HTMP).

The success criteria for the CanopySense pilot will include the accuracy of automated trim prescriptions that match a corresponding field-verified trim prescription for the piloted circuits/areas. Other success criteria for Crown Segmentation will include the accuracy of how well individual tree canopies (crowns) can be defined compared to existing manually collected inventory records.

Figure SCE-RN-SCE-26-09: SCE Vegetation Management Remote Sensing Journey



9.2.2 Inspections for Vegetation Clearances from Transmission Lines (VM-8)

9.2.2.1 Overview and Area Inspected

In this section, the electrical corporation must provide an overview of the inspection(activity) program. This overview must describe where the electrical corporation performs the inspection activities (programs) (e.g., Service Territory, HFTD only, Areas of Concern, etc.)

Inspections for vegetation clearances from transmission lines aim to prevent vegetation from encroaching upon transmission assets, thereby maintaining system reliability and reducing wildfire risk. Similar to distribution, transmission circuit miles are inspected by ground-based patrols and/or remote sensing methods throughout SCE's service territory.

In 2025, SCE is using remote sensing technology along Transmission lines as a supplemental tool for ground-based circuit inspections. SCE provides remote sensing data, when available, to inspectors prior to conducting foot patrols to assist them in identifying potential encroachments and help validate clearances. Modeling based on remote sensing data calculates the maximum sag and sway of conductors under peak current and wind loads.

9.2.2.2 Procedures

In this section, the electrical corporation must list the procedures, including the version(s) and effective date(s), for the inspection activity (program).

SCE's procedures for VM-8 are documented in Transmission Vegetation Management Plan (UVM-02), Version 8, effective date April 1, 2024; LiDAR Schedule Reference Guide (UVM-06), Version 2, effective date May 17, 2019; and Inspection Manual (UVM-09), Version 7, effective date June 30, 2024.

9.2.2.3 Clearance

In this section, the electrical corporation must describe how clearances are determined and prescribed through this inspection activity (program) (e.g., GO 95 Table 1, GO 95 Appendix E, ANSI A- 300, etc.). As applicable, the electrical corporation must describe how it differently prescribes clearances for high-risk species of vegetation.

SCE uses the GRCD to determine clearances for transmission lines which are based on clearance zones stated in the following regulations: FAC-003-5, GO 95 Rule 35 (Case 13 and Case 14), GO 95 Rule 37, PRC 4293, PRC 4292, Title 14 CCR Sections 1250-1258. In HFRA, SCE strives to obtain expanded clearances of 30 feet for transmission lines. At a minimum, within HFRA, SCE maintains at least the required 10 feet clearance for transmission lines. SCE has incorporated expanded clearances into its routine inspection scope and utilizes the GRCD to verify whether an expanded clearance has been obtained. Vegetation Inspections assess whether the vegetation meets these clearance requirements and prescribe corrective actions if necessary.

For details on management of high-risk species of vegetation, refer to section 9.2.1.3.

9.2.2.4 Fall-in Mitigation

In this section, the electrical corporation must describe how it identifies fall-in risks, such as hazard trees, during the inspection (e.g., Level 1, Level 2, etc.). As applicable, the electrical corporation must describe how it differently prescribes removal of high-risk species of vegetation.

Fall-in mitigation is primarily addressed through SCE's Hazard Tree and Dead and Dying Tree Programs. Please refer to sections 9.2.3.4 and 9.2.4.4.

9.2.2.5 Scheduling

In this section, the electrical corporation must describe how the inspection activity (program) is scheduled. This must include the frequency (e.g., annual, quarterly, three-year cycle) and/or triggers (e.g., severe weather events, risk model outputs) of the inspection activity (program). It must also identify how the frequency and/or trigger might differ by HFTD tier or other risk designation.

If the inspection activity (program) is based on a fixed frequency (e.g., annual, three-year cycle), the electrical corporation must explain how it uses risk prioritization in the scheduling of the inspection activity (program) to target high-risk areas). If the electrical corporation does not use risk prioritization in the scheduling of the inspection activity (program), it must explain why.

SCE uses the same procedures for scheduling inspections for vegetation clearances from transmission lines[157] and distribution lines. See section 9.2.1.5 for details.

SCE targets annual vegetation inspections for all transmission HFRA circuit miles. Completion of this scope may be constrained by environmental conditions and risk prioritization efforts. Circuit mileage totals are dynamic and may shift due to HFRA boundary changes, GIS and data refinements, and asset-related adjustments such as conductor span length variations due to asset removal or installation.

9.2.2.6 Updates

In this section, the electrical corporation must discuss changes/updates to the inspection activity (program) since its last WMP submission, including known future plans (beyond the current year) and new/novel strategies the electrical corporation may implement in the next five years (e.g., references to and strategies from pilot projects and research). The electrical corporation must include lessons learned as applicable.

In this 2026-2028 WMP, SCE is combining two prior WMP activities – expanded clearances for transmission lines (VM-8) and remote sensing transmission inspections (VM-10) – into a single WMP activity called "Inspections for Vegetation Clearance from Transmission Lines" (new VM-8). It is beneficial to combine the remote sensing and ground inspections because SCE plans to augment VM-8 by increasing the use of remote sensing technologies in its inspections.

As mentioned above in 9.2.1.6, in 2025 and beyond, SCE plans to introduce use of CanopySense for vegetation management inspection activities around transmission lines.

9.2.3 Hazard Tree Management Program (VM-1)

9.2.3.1 Overview and Area Inspected

In this section, the electrical corporation must provide an overview of the inspection (activity) program. This overview must describe where the electrical corporation performs the inspection activities (programs) (e.g., Service Territory, HFTD only, Areas of Concern, etc.)

SCE's Hazard Tree Management Program (HTMP) identifies and mitigates fall-in risk to SCE's electrical assets posed by green or live trees with specific conditions. SCE prioritizes locations within HFRA based on the Tree Risk Index (TRI). Within the TRI methodology, each structure in HFRA is evaluated for the risk of vegetation contact and is assigned a probability of ignition (POI) as well as a Technosylva consequence score (which estimates the potential number of acres burned should an ignition occur at the location of the structure). These structures with assigned POI and consequence scores are then aggregated to the grid/circuit level and assessed for alignment with IWMS severe risk areas. Grids/circuits are then assigned to risk categories A, B, C, and D (with A being the highest risk category) according to their TRI score.

9.2.3.2 Procedures

In this section, the electrical corporation must list the procedures, including the version(s) and effective date(s), for the inspection activity (program).

SCE's HTMP is documented in SCE's Utility Vegetation Management (UVM) procedure, UVM-04 "Hazard Tree Management Program" (Version 3, effective April 1, 2024) and UVM-09 "Inspection Manual" (Version 7, effective June 30, 2024).

9.2.3.3 Clearance

In this section, the electrical corporation must describe how clearances are determined and prescribed through this inspection activity (program) (e.g., GO 95 Table 1, GO 95 Appendix E, ANSI A- 300, etc.). As applicable, the electrical corporation must describe how it differently prescribes clearances for high-risk species of vegetation.

Hazard Tree Management is distinct from other inspection activities that focus on establishing clearances from power lines, as it specifically targets fall-in risk posed by trees located outside of the prescribed clearance zones that can impact electrical facilities and potentially lead to ignitions and outages. Hazard Tree Management clearance activities involve trimming or removing trees and vegetation that are within striking distance from SCE equipment.

Mitigations are prescribed in alignment with ANSI A300 (Part 9) and ISA Tree Risk Assessment guidelines, which provide standards for tree risk assessment.

For high-risk species of vegetation, HTMP considers the tree risk attributes, strike potential and likelihood of impact on SCE assets (as outlined in UVM-04 and UVM-09). HTMP utilizes the Tree Risk Calculator (TRC) which incorporates a species risk rating (Low, Medium, or High) in the score calculation for determining treatment of high-risk species with strike potential.

9.2.3.4 Fall-in Mitigation

In this section, the electrical corporation must describe how it identifies fall-in risks, such as hazard trees, during the inspection (e.g., Level 1, Level 2, etc.). As applicable, the electrical corporation must describe how it differently prescribes removal of high-risk species of vegetation.

HTMP utilizes a Level 1 and Level 2 assessment conducted by an International Society of Arboriculture (ISA) certified arborists to quantify fall-in risks. A Level 1 Limited Visual Assessment is performed as the initial inspection. If strike potential is identified during the Level 1 assessment within the Utility Strike Zone (USZ), a Level 2 Basic Assessment of the tree will be conducted.

Level 1: Limited Visual Assessment

This is accomplished by conducting an assessment from one side of the tree (side nearest the electric facilities) and can be ground-based, vehicle-based, or aerial-based (e.g., fixed-wing, helicopter, drone, LiDAR), as appropriate for the site conditions, type of infrastructure, and tree population being considered. Strike potential is identified during the Level 1 Assessment.

Level 2: Basic Assessment

This is a detailed ground-based visual assessment of an individual tree and its surrounding site. A Level 2 assessment may include looking at the site, buttress roots, trunk, and branches.

Level 2 assessments are completed by an ISA certified arborist to identify subject trees that could potentially fall into or otherwise impact electrical facilities in HFRA. The arborists inspect trees in the area on either side of SCE's electrical facilities from which a tree or a portion of a tree could strike or impact electrical facilities. This area can vary significantly based on the height of the trees, slope conditions, and the potential for impacts from wind-driven vegetation.

HTMP inspectors use the TRC to document tree defects and likelihood of failure and target impact. The TRC involves an ISA certified arborist assigning a risk score based on established criteria depending on the inspector's assessment results. Using the TRC, a tree is classified into one of two categories: (1) a subject tree that does not need mitigation but is added to SCE's tree inventory for continued monitoring, or (2) a hazard tree needing mitigation (trim) or removal.

A subject tree is a tree within SCE's tree inventory that is identified as low-risk and with a typical risk score between 0 to 49. A hazard tree needing mitigation, while alive, typically has a risk score between 50 to 100. However, the need to mitigate a hazard tree is not solely dependent on and/or limited to risk scores of 50 and above. The classification of the tree and arborist expert assessment informs the specific remediation prescribed.

SCE may prescribe the following mitigations based on the risk assessment results:

- **Complete Tree Removal**: This is the preferred mitigation action when the distance between the tree and SCE's lines or facilities is equal to or less than the height of the tree and make-safe mitigation is not feasible. Complete removal is also prescribed when the tree poses a significant risk to electric facilities and shows characteristics that make the tree, or parts thereof, unstable.

- **Make-Safe Procedures**: In some situations, complete tree removal may not be required. Portions of a tree can be pruned or removed to mitigate the risk if appropriate conditions exist. Make-safe procedures are used when the hazard condition is not caused or exacerbated by site considerations.

Please refer to section 9.2.3.3 above for details on how high-risk species of vegetation are managed within HTMP.

9.2.3.5 Scheduling

In this section, the electrical corporation must describe how the inspection activity (program) is scheduled. This must include the frequency (e.g., annual, quarterly, three-year cycle) and/or triggers (e.g., severe weather events, risk model outputs) of the inspection activity (program). It must also identify how the frequency and/or trigger might differ by HFTD tier or other risk designation.

If the inspection activity (program) is based on a fixed frequency (e.g., annual, three-year cycle), the electrical corporation must explain how it uses risk prioritization in the scheduling of the inspection activity (program) to target high-risk areas). If the electrical corporation does not use risk prioritization in the scheduling of the inspection activity (program), it must explain why.

HTMP is focused on SCE's HFRA. HTMP inspection scope and frequency are driven by the Tree Risk Index (TRI) model. Please refer to 9.2.3.1 for a description of the TRI model.

Based on their TRI score, grids/circuits in the highest risk category of A follow an annual cycle for HTMP inspections, while grids/circuits in categories B, C, and D follow a three-year inspection cycle for HTMP. Any hazardous tree that was trimmed as a mitigation prescription in prior HTMP inspection cycles will continue to be inspected as part of its respective grid/circuit based on TRI ranking. This methodology is refreshed annually for new subject trees recorded in each category.

9.2.3.6 Updates

In this section, the electrical corporation must discuss changes/updates to the inspection activity (program) since its last WMP submission, including known future plans (beyond the current year) and new/novel strategies the electrical corporation may implement in the next five years (e.g., references to and strategies from pilot projects and research). The electrical corporation must include lessons learned as applicable.

As mentioned earlier, in 2023 and 2024, SCE consolidated inspections for Routine Line Clearing, Hazard Tree Management Program and Dead & Dying Tree Removal Program. In addition, SCE has also consolidated resources (utilizing the same vendor that will employ certified Arborists, as applicable).

SCE reviewed the TRI scores for the lower risk categories (B, C, & D) and is considering that for 2026-2028, instead of completing each category in separate sequential years, the HTMP scope for B, C & D could be combined. A third of this combined scope would be executed annually to achieve workflow efficiency until the scope is completed. The scope for TRI category A would continue to be executed annually.

In 2024, SCE made changes to the TRC to better identify the likelihood of failure and strike potential of hazard trees. In 2026-2028, SCE will continue to assess and update the TRC based on lessons learned and ongoing data analysis.

In 2026-2028, SCE will continue to use ground-based inspections to validate and ensure the accuracy of remote sensing data used for identifying trees with strike potential.

9.2.4 Dead and Dying Tree Removal (VM-4)

9.2.4.1 Overview and Area Inspected

In this section, the electrical corporation must provide an overview of the inspection (activity) program. This overview must describe where the electrical corporation performs the inspection activities (programs) (e.g., Service Territory, HFTD only, Areas of Concern, etc.)

In the Dead and Dying Tree Removal Program, currently SCE uses ground crews to patrol its HFRA to identify dead and dying trees for removal. A tree is classified as dead when the canopy has declined 75% or greater and/or is significantly infected with bark beetles or other invasive insects. Dead and dying trees have a higher probability of failing, and if within striking distance of SCE lines and equipment, can cause fault conditions, sparks, and/or ignitions. Unlike the other programs that focus on maintaining clearances and mitigating risks from living trees and vegetation that can encroach or adversely impact SCE infrastructure, the Dead and Dying Tree Removal Program specifically aims to eliminate trees that are dead or have reached a critical state of decline.

After an inspection is performed and the prescription is generated, SCE will remove the tree consistent with industry practice.

9.2.4.2 Procedures

In this section, the electrical corporation must list the procedures, including the version(s) and effective date(s), for the inspection activity (program).

SCE's Dead and Dying Removal Tree Program is documented in SCE's UVM procedure UVM-18, "Assessment and Removal of Dead and Dying Trees" (Version 1, effective December 1, 2021).

9.2.4.3 Clearance

In this section, the electrical corporation must describe how clearances are determined and prescribed through this inspection activity (program) (e.g., GO 95 Table 1, GO 95 Appendix E, ANSI A- 300, etc.). As applicable, the electrical corporation must describe how it differently prescribes clearances for high-risk species of vegetation.

Inspectors that assess dead and dying trees typically focus on trees that have the potential to strike (dependent on height of conductors and surrounding trees) SCE Transmission or Distribution facilities, including but not limited to primary conductors and other structures.

Under the Dead and Dying Tree Removal program, SCE follows the criteria (i.e., a tree is classified as dead when the canopy has declined 75% or greater and/or is significantly infected with bark beetles or other invasive insects) for identifying dead and dying trees regardless of the tree species. Clearance activities for dead and dying involves removing trees and vegetation that are within striking distance from SCE equipment.

9.2.4.4 Fall-in Mitigation

In this section, the electrical corporation must describe how it identifies fall-in risks, such as hazard trees, during the inspection (e.g., Level 1, Level 2, etc.). As applicable, the electrical corporation must of describe how it differently prescribes removal of high-risk species of vegetation.

For Dead and Dying Tree Removal the assessment performed is a Level 1 assessment, in accordance with ANSI A300 (Part 9). This is accomplished by conducting an assessment from one side of the tree (side nearest the electric facilities) as appropriate for the site conditions, type of infrastructure, and tree population being considered. A Level 1 assessment focuses on identifying obvious tree defects (i.e., dead branches, leaning) that are observable from the side of the tree nearest to the electric facilities. All trees that are identified within strike distance of SCE overhead facilities that are dead or expected to die within one year are prescribed for removal.

9.2.4.5 Scheduling

In this section, the electrical corporation must describe how the inspection activity (program) is scheduled. This must include the frequency (e.g., annual, quarterly, three-year cycle) and/or triggers (e.g., severe weather events, risk model outputs) of the inspection activity (program). It must also identify how the frequency and/or trigger might differ by HFTD tier or other risk designation. If the inspection activity (program) is based on a fixed frequency (e.g., annual, three-year cycle), the electrical corporation must explain how it uses risk prioritization in the scheduling of the inspection activity (program) to target high-risk areas). If the electrical corporation does not use risk prioritization in the scheduling of the inspection activity (program), it must explain why.

For the Dead and Dying Tree Removal program, inspections are performed annually by pre-inspectors, in applicable areas within HFTD Tier 2 and Tier 3. Applicable areas are determined based on California's Tree Mortality Task Force, which updates maps annually to show High Hazard Zones and Hazard Severity Zones. SCE utilizes these Tree Mortality Task Force categories to incorporate risk prioritization into the Dead and Dying Tree inspection scope. All Hazard Severity Zones and HFTD tiers 2 and 3 have been mapped to a grid/circuit and documented in SCE's vegetation work management tool based on planning month. Building off the Routine Line Clearing schedule (which covers all SCE service territory, and not just the applicable areas within HFTD Tier 2 and Tier 3 targeted by the Dead and Dying Tree Removal program), inspectors who are sent during "cycle buster"[158] visits

[158] Cycle buster visits typically occur on a six-month cadence and are intended to address vegetation that may not make it through the annual routine trim cycle without encroaching on the required minimum clearances and which may therefore require pruning midterm before the routine cycle is completed.

looking for uncharacteristic growth are also able to identify dead and dying trees in addition to routine maintenance.

9.2.4.6 Updates

In this section, the electrical corporation must discuss changes/updates to the inspection activity (program) since its last WMP submission, including known future plans (beyond the current year) and new/novel strategies the electrical corporation may implement in the next five years (e.g., references to and strategies from pilot projects and research). The electrical corporation must include lessons learned as applicable.

As mentioned in section 9.2.1.6, SCE completed implementation of a centralized inspection schedule to consolidate the inspection process for Inspections for Vegetation Clearances from Distribution and Transmission Lines, HTMP, and Dead and Dying Tree Removal Program.

In 2026-2028, depending on successful introduction and validation of CanopySense data models for determination of inspection clearances (VM-7 & VM-8), SCE also plans to explore the use of remote sensing for detecting dead and dying trees.

9.3 Pruning and Removal

9.3.1 Overview

In this section, the electrical corporation must provide an overview of the subsequent pruning, removal, and other vegetation management activities that are performed as a result of inspections.

SCE performs pruning and removal which involves the physical cutting and removal of vegetation to maintain the required clearances around electrical lines and equipment through its vegetation management programs (VM-1, VM-4, VM-7, and VM-8).

9.3.2 Procedures

In this section, the electrical corporation must list the procedures, including the version(s) and effective date(s), for subsequent pruning, removal, and other vegetation management activities that are performed as a result of inspections.

SCE's procedures for pruning and removal are outlined in the following documents:

- Transmission Vegetation Management Plan (UVM-02), Version 8, effective date April 1, 2024
- Distribution Vegetation Management Plan (UVM-03), Version 6, effective date April 1, 2024
- Hazard Tree Management Plan (UVM-04), Version 3, effective April 1, 2024
- Managing Vegetation Threats (UVM-08), Version 16, effective March 24, 2025
- Inspection Manual (UVM-09), Version 7, effective date June 30, 2024
- Assessment and Removal of Dead and Dying Trees (UVM-18), Version 1, effective December 1, 2021

9.3.3 Scheduling

In this section, the electrical corporation must describe how subsequent pruning, removal, and other vegetation management activities that are performed as a result of inspections are scheduled. This must include the timeline(s) in which clearance and removal work prescribed by an inspection activity (program) will be completed and how the timeline differs by HFTD tier or other risk designation.

SCE creates work orders for scheduling subsequent pruning and removal activities based on identified threats determined through the various inspection activities (VM-1, VM-4, VM-7, and VM-8). These threats are categorized into different priority levels, for which SCE has developed internal timelines (documented in UVM-08) for completion. SCE categorizes vegetation work orders as Priority 1 (P1) or Priority 2 (P2). Please refer to section 9.12.1 for details on priority assignment for work orders.

9.3.4 Updates

In this section, the electrical corporation must discuss changes/updates to pruning and removal activities since the last WMP submission, including known future plans (beyond the current year) and new/novel strategies the electrical corporation may implement in the next five years (e.g., references to and strategies from pilot projects and research). The electrical corporation must include lessons learned as applicable.

Since expanded clearance implementation began in 2019, SCE has observed a reduction in vegetation-caused outage events. This trend has continued year-over-year; therefore, SCE has standardized expanded clearances and incorporated the Grid Resiliency Clearance Distance (GRCD) into the Routine Line Clearing scope of work going forward. SCE will continue to maintain achieved distances from previous work cycles. Challenges in achieving GRCD include, but are not limited to, environmental restrictions (nests, protected species, etc.), tree health considerations, site conditions, property owner approval, or alternative engineering solutions (aerial cable, covered conductor, etc.).

9.4 Pole Clearing

9.4.1 Overview

In this section, the electrical corporation must provide an overview of pole clearing, including:

- *Pole clearing performed in compliance with Public Resources Code section 4292*
- *Pole clearing outside the requirements of Public Resources Code section 4292 (e.g., pole clearing performed outside of the State Responsibility Area)*

9.4.1.1 Compliance Structure Brushing (VM-2.2)

SCE removes vegetation around all Distribution poles and Transmission structures subject to PRC 4292 in State Responsibility Areas (SRA). The structure brushing program maintains clearance from the ground up to eight feet. Clearances above eight feet are maintained in the Routine Line Clearing Programs (VM-7 and VM-8).

9.4.1.2 Additional Structure Brushing (VM-2.1)

In addition to performing structure brushing in compliance with PRC 4292, SCE attempts to brush additional structures outside the State Responsibility Area in HFRA for risk mitigation. The Additional Structure Brushing scope is identified in alignment with SCE's IWMS. The structure brushing scope could include transmission and distribution structures in Severe Risk Areas and High Consequence Areas within IWMS. Additionally, SCE considers more near-term drivers (e.g. weather, drought conditions, etc.) through prioritizing AOCs within its structure brushing scope.

SCE's additional structure brushing activity targets are provided in Table 9-2. If factors outside of SCE's control allow for execution of additional units, SCE will strive to inspect 172,000 structures annually and perform clearance where necessary in SCE's HFRA. This level of execution depends on exogenous factors like the issuance of environmental permits and property access.

9.4.2 Procedures

In this section, the electrical corporation must list applicable electrical corporation procedure(s), including the version(s) and effective date(s), used to execute pole clearing.

SCE's structure brushing program is documented in its Utility Vegetation Management procedure, UVM-20 "Structure Brushing" (Version 4, effective March 24, 2025).

9.4.3 Scheduling

In this section, the electrical corporation must describe how pole clearing is scheduled. This must include how the schedule is affected by HFTD tier or other risk designation.

Structure Brushing is an annual clearance program. SCE considers both regulatory compliance and ignition risk in prioritizing the brushing schedule, as well as access issues (e.g., landowner consents, environmental approvals) and operational efficiency. Work is scheduled by region and district, based on environmental approvals and scope. Factors such as location (e.g., SRA, High Fire Risk Areas), applicability of PRC 4292 requirements, weather, environmental constraints, and prior calendar year activity are all considered to determine the scheduled month. To reduce wildfire risk, SCE's Structure Brushing Program brushes all available structures in scope for VM2.1 and VM-2.2, including structures with non-exempt equipment, in accordance with PRC 4292. The number of structures listed in Table 9-2 includes structures applicable to each program, as of August 2025, and are adjusted by approximately 20 percent based on the historical customer and environmental constraint rates. These exemptions are allowed under PRC 4292. Additionally, the total number of structures completed may vary due to changes in equipment, HFRA boundary changes, and regulatory requirements. Despite the constraints mentioned above, SCE makes reasonable attempts and strives to brush all structures that are identified for structure brushing in HFRA and under PRC 4292.

9.4.4 Updates

In this section, the electrical corporation must describe changes to pole clearing since the last WMP submission and a brief explanation as to why those changes were made. Discuss any planned improvements or updates to pole clearing and the timeline for implementation.

In 2023, SCE transitioned prioritizing its structure brushing to align with SCE's IWMS by targeting structures in severe risk areas and high consequence areas.

Since the last WMP submission, SCE has expanded the scope of Additional Structure Brushing. In 2024, SCE made incremental adjustments to include transmission structures to its Additional Structure Brushing scope for 2025 as prioritized by IWMS. Additionally, SCE adjusted the sub-transmission structure brushing scope in response to the Climate Adaptation Vulnerability Assessment, adding approximately 200 structures.

9.5 Wood and Slash Management

9.5.1 Overview

In this section, the electrical corporation must provide an overview of how it manages all downed wood and slash generated from vegetation management activities.

SCE reduces slash (e.g., cut limbs and other wood debris) resulting from vegetation management activities by directing pruning or tree removal contractors to chip and haul the material away to be disposed or recycled, subject to constraints and customer requests. SCE's Statement of Work (SOW) requires contractors to rake up and dispose of vegetation, and to leave work sites in a condition consistent with the condition before work was performed.

9.5.2 Procedures

In this section, the electrical corporation must list applicable electrical corporation procedure(s), including the version(s) and effective date(s), used to manage wood and slash.

Reducing slash from Vegetation Management initiatives is a standard prudent practice conducted during and after Vegetation Management activities, as documented in SCE's contractor Statement of Work. SCE requires Vegetation Management contractors to include debris removal as part of their vegetation management activities, with a few exceptions such as remote forested areas where lopping and scattering of debris is permitted by land agencies or when requested by customers. SCE defines "debris", in a broader context encompassing any organic material, including slash, that accumulates in proximity to trees as woody debris generated from vegetation activities as well as natural processes.

SCE's pruning and removal contractors abide by the standard cleanup and disposal expectations for work sites. Removal and disposal of all debris (including debris greater than 4") generated during SCE vegetation management activity is typically performed the same day, except as requested by the customer (e.g., for firewood or mulch) or where logistical constraints exist (e.g., steep slope with no vehicular access). Debris management is documented in SCE's Work Management System and indicates the specific action the contractor implemented for the debris management, such as cleanup all debris, cut and scatter, leave brush, cut to firewood.

9.5.3 Scheduling

In this section, the electrical corporation must describe how wood and slash management is scheduled. This must include how the schedule is affected by HFTD tier or other risk designation.

Wood and slash management activities are not typically scheduled separately but rather conducted by the tree trimming and removal contractors as part of their scope of vegetation management activities. Refer to Section 9.2.3 for Hazard Tree and Section 9.3.2 for Procedures.

9.5.4 Updates

In this section, the electrical corporation must describe changes to wood and slash management since the last WMP submission and a brief explanation as to why those changes were made. Discuss any planned improvements or updates to wood and slash management and the timeline for implementation.

SCE has benchmarked with other utilities and found that current procedures align with utility industry practices. In 2024, SCE piloted a debris tracking tool with our contract workforce and will continue to evaluate the benefits of maintaining this data.

SCE established a qualitative target (VM-11) with the objective of continuing the evaluation of debris management practices and improving contractual agreements with vendors where practical.

9.6 Defensible Space

9.6.1 Overview

In this section, the electrical corporation must provide an overview of its action taken to reduce wildfire risk to substations, generation facilities, and other electrical facilities in accordance with Public Resources Code section 4291, other defensible space codes and regulations, or in exceedance of these requirements.

SCE inspects vegetation around its substations and generation facilities for potential risks from encroachment or blow-in or fall-in hazards and manages vegetation around these facilities by performing pruning, removal, and weed abatement. Vegetation contact with energized conductors and equipment is the primary risk to be mitigated, as well as preventing fire damage to substations and generation assets.

9.6.2 Procedures

In this section, the electrical corporation must list applicable electrical corporation procedure(s), including the version(s) and effective date(s), used to create and maintain defensible space.

SCE documents its procedures for maintaining defensible space in its Substation Operations and Maintenance Policy and Procedures (SOM), effective November 22, 2024.

9.6.3 Scheduling

In this section, the electrical corporation must describe how creation and maintenance of defensible space are scheduled. This must include how the schedule is affected by HFTD tier or other risk designation.

SCE performs routine substation inspections in accordance with GO 174 to identify any issues including but not limited to vegetation encroachment. Identified issues are documented, reviewed and assigned a remediation priority.

SCE has also identified certain non-energized facilities to be inspected and treated over a three-year period. SCE uses a risk-based approach to schedule sites for treatment in HFRA only. Specifically, non-energized facilities within HFTD Tier 3 were prioritized for inspection and treatment in 2026. The remaining facilities fall within the HFTD Tier 2 and are scheduled for inspection and treatment in 2027 and 2028. Facilities are scheduled within both HFTD Tier 3 and Tier 2 based on geographical location, linear distance/length of each facility, and resource availability.

9.6.4 Updates

In this section, the electrical corporation must describe changes to how it creates or maintains defensible space since the last WMP submission and a brief explanation as to why those changes were made. Discuss any planned improvements or updates to defensible space and the timeline for implementation.

In 2024, SCE completed VM-3 (Expanded Clearances for Generation Legacy Facilities). The expanded clearances for generation legacy facilities have been established and will be maintained through routine vegetation management activities.
For this 2026-2028 WMP, SCE established a new qualitative target VM-14 with the objective of conducting field inspections of non-energized water conveyance generation facilities to develop a proposed expanded clearance treatment scope.

9.7 Integrated Vegetation Management

9.7.1 Overview

In this section, the electrical corporation must provide an overview of its actions taken for activities not covered in previous sections and performed in accordance with Integrated Vegetation Management principles. This may include, but is not limited to, the following activities: the strategic use of herbicides, growth regulators, or other chemical controls; tree-replacement activities (programs); promotion of native shrubs; prescribed fire; or other fuel treatment activities.

SCE's IVM practices primarily focus on reclaiming overgrown ROW (Right of Way) and maintaining the sites to reduce vegetation.

SCE considers various factors when identifying sites for the IVM practices such as high inventory counts, frequency of maintenance and potential impact from wildfires. SCE continuously evaluates IVM technologies that are most suitable for the service territory. Implementation of IVM practices may be impacted due to several constraints, including but not limited to, permitting and resource constraints.

The intent of this practice is to discourage the growth of undesirable plant species using a combination of herbicides, mowing and hand cutting.

9.7.2 Procedures

In this section, the electrical corporation must list applicable electrical corporation procedure(s), including the version(s) and effective date(s), used for integrated vegetation management.

SCE's procedures for IVM are documented in Utility Vegetation Management Integrated Vegetation Management Plan (UVM-05), Version 2, effective May 17, 2019.

9.7.3 Scheduling

In this section, the electrical corporation must describe how integrated vegetation management activities are scheduled. This must include how the schedule is affected by HFTD tier or other risk designation.

SCE's scheduling for IVM is based on annual maintenance work plans for other programs. For example, once routine maintenance has been completed, additional mowing, hand clearing or herbicide application can take place to extend the maintenance cycles between clearing activities. Mowing and/or herbicide are seasonally dependent and are performed when appropriate.

9.7.4 Updates

In this section, the electrical corporation must describe changes to its integrated vegetation management activities since the last WMP submission and a brief explanation as to why those changes were made. Discuss any planned improvements or updates to integrated vegetation management and the timeline for implementation.

SCE explored several pilots during the last WMP filing period, described below:

- SCE tested the use of Tree Growth Regulators (TGR). TGR is a method of potentially slowing tree growth rates to extend trim cycles and/or reduce the frequency of visits. SCE piloted this effort between October 2021 through January 2024, which monitored approximately 650 trees within the City of Visalia. During the course of testing, it was found the TGR material did not reduce growth to the extent needed to achieve a reduction in trims. Additionally, growth reductions were inconsistent from species to species, and therefore TGR was not considered a reliable tool for future treatment. In March of 2024, SCE discontinued the TGR pilot program.
- SCE explored the use of goat grazing. However, due to cost and overall effectiveness compared to other methods of controlling vegetation, SCE limits the use of goat grazing to specific areas where mowing or herbicide use is restricted.
- The Low Growth pilot was used to provide proof of concept for IVM methods on weed abatement parcels where higher than average number mowing passes take place annually. The Low Growth pilot was designed to use various control methods (mechanical, chemical and biological) to eliminate the undesirable plant species that require annual maintenance. Herbicide was determined to be the most effective treatment method. Herbicide treatments have been integrated into the VM Weed Abatement program and will be a source of controlling vegetation on fee-owned ROW where practical.
- SCE evaluated the use of heli-saw as an alternative method of bulk tree trimming by utilizing helicopters to trim trees. Based on research and experience from other entities, SCE determined not to pursue the use of heli-saws for tree trimming.

Based on the results of these pilots SCE plans to update UVM-05 to account for lessons learned and provide greater clarity with Integrated Vegetation Management treatment methodologies.

For this 2026-2028 WMP, SCE established a new qualitative target VM-13 to evaluate and expand treatment methodologies across required vegetation management activities.

9.8 Partnerships

In this section, the electrical corporation must provide information on its partnerships with other entities in vegetation management. This may include partnerships with government agencies, non-profit organizations, or coalitions, such as Regional Forest and Fire Capacity Program grantees and local forest collaboratives. For this section, "partnership" is defined as the combining of resources, expertise, and efforts to accomplish agreed upon objectives related to wildfire risk reduction achieved through vegetation management. The electrical corporation must provide the following summary information in table format for current partnerships and future partnerships the electrical corporation plans to enter during the three years of the WMP cycle:

- *Names of all agencies, organizations, or coalitions in the partnership.*
- *Vegetation management activities performed pursuant to or under the partnership (e.g., thinning, prescribed fire, mastication, invasive plant removal, woody debris management, etc.).*
- *The objective of the activities performed pursuant to or under the partnership.*
- *Electrical corporation's role in the coordination or partnership (e.g., funding, labor, landowner, etc.).*
- *Anticipated accomplishments of partnership projects during the three years of the WMP cycle, including work done by the electrical corporation and work done by the partnering agency/organization (e.g. number of acres treated, number of trees planted, number of personnel trained, etc.).*

Table 9-4 provides an example of the appropriate level of detail and the required format.

Table 9-4: Partnerships in Vegetation Management

Partnering Agency/ Organization	Activities	Objectives	Electrical Corporation Role	Anticipated Accomplishments
Cal Fire – Operation Santa Ana	Inspecting areas where fire propagation is the highest risk.	Verifying vegetation compliance with State regulations through pole and powerline inspections.	Joint agency partnership between SCE and the fire agencies.	Meeting annually to perform targeted compliance inspections.
Cal Poly WUI Fire Institute	Address growing challenges posed by wildfires, particularly in high fire risk zones,	Strategic collaboration aimed at enhancing wildfire resilience, advancing research, and improving fire	Initial funding resources for the creation of the Cal Poly WUI Fire Institute since	Actively participate in Advisory Council to provide strategic direction and participate in

Partnering Agency/ Organization	Activities	Objectives	Electrical Corporation Role	Anticipated Accomplishments
	incorporating scientific research, technology integration, policy development, and community engagement.	management practices in areas where natural landscapes intersect with human development.	2021 giving $1M per year which ended in 2023.	specific research projects as appropriate.
San Bernardino Community College District (California Community College District)	Expand and evolve the Arborist training program with additional course material to strengthen SCE workforce.	Upscaling internal and external work forces for future sustainability.	Partnership to develop course material specific to utility vegetation management and wildfire prevention.	SCE plans to expand the program and develop additional course material for Arborist Training that will benefit our internal and external workforce.
U.S. Forest Service (USFS) Region 5	Collaborate on vegetation management, and the development of rapid response protocols during fire events.	Focus on reducing wildfire risks and enhancing grid resilience in forested areas.	Collaborative partnership driven by a shared goal of balancing reliable energy delivery with wildfire risk reduction.	Future projects focus on fuels reduction, timber management, and strengthening our communications for better forecasting on future project workloads.
International Wildfire Risk Mitigation Consortium (IWRMC)	Sharing experiences on the strategy and execution of wildfire mitigation activities.	Create a framework for utilities worldwide to jointly combat global wildfire threats.	SCE partnered with other California investor-owned utilities worldwide to form the IWRMC.	Future projects are being discussed between the parties. In 2023, SCE led the first project to study vegetation management and hazard tree best practice. This initiative was completed in August 2024.

The electrical corporation must also provide a narrative overview of, in order: 1) each current and future vegetation management partnership identified in Table 9-3 and 2) vegetation management partnerships it is discontinuing or has discontinued since the last WMP submission and explain why it is discontinuing or has discontinued the vegetation management partnership. Section 9.8.1 provides instructions for the overviews. The sections must be numbered Section 9.8.1 to Section 9.8.n (i.e., each vegetation management *partnership is detailed in its own section) with the names of the partnering agencies or organizations as the section title.*

9.8.1 State Fire Agency Partnership (Cal Fire) – Operation Santa Ana

9.8.1.1 Overview

In this section, the electrical corporation must provide an overview of the vegetation management partnership including status of the partnership (current, future, or discontinued) and a description of the type of work accomplished through this partnership. This overview must describe where the work accomplished through this partnership takes place (e.g., Service Territory, HFTD only, a specific county, etc.). If available, provide a link to any website associated with the partnership.

Operation Santa Ana is a joint agency partnership between SCE and State/County Fire Authorities to verify vegetation compliance with state regulations through pole and powerline inspections. The inspection is performed annually, and the scope is informed by the respective fire agency, which includes a mix of SRA and HFRA boundaries.

The scope typically targets areas with higher risk of fire propagation.

9.8.1.2 Partnership History

In this section, the electrical corporation must provide a history of the vegetation management partnership including how long the electrical corporation has been working with the partnering agency/organization, the number of projects completed or in-progress, the scope of completed and in-progress projects (e.g., acres treated, trees planted, etc.), and the electrical corporation's quantitative contribution to the project (e.g. dollars contributed, number of workers provided, number of hours of consultation).

The first meeting between SCE and the fire agencies to discuss joint patrols was held in 1999. Participants included SCE, California Department of Forestry and Fire Protection (CAL FIRE) County Fire Authorities (Orange, Los Angeles, Kern, Santa Barbara, Ventura). Since 1999, SCE meets annually to perform targeted compliance joint inspections.

9.8.1.2 Future Projects

In this section, the electrical corporation must provide a description of projects with the partnering agency/organization that are currently planned for the three years of the WMP cycle, have not yet begun, and are fully funded. This description must include the scope of future projects (e.g., acres treated, trees planted, etc.), projected completion years, and the electrical corporation's quantitative contribution to the project (e.g. dollars contributed, number of workers provided, number of hours of consultation).

SCE continues to hold annual meetings with fire authorities and annually inspect selected areas based on the needs assessed by the fire authorities.

9.8.2 Educational Institution Partnership (Cal Poly Wildland Urban Interface)

9.8.2.1 Overview

In this section, the electrical corporation must provide an overview of the vegetation management partnership including status of the partnership (current, future, or discontinued) and a description of the type of work accomplished through this partnership. This overview must describe where the work accomplished through this partnership takes place (e.g., service territory, HFTD only, a specific county, etc.). If available, provide a link to any website associated with the partnership.

The partnership with the Cal Poly Wildland Urban Interface (WUI) Fire Institute represents a strategic collaboration aimed at enhancing wildfire resilience, advancing research, and improving fire management practices in areas where natural landscapes intersect with human development. This alliance is designed to address the growing challenges posed by wildfires, particularly in high fire risk zones, through a combination of scientific research, technology integration, policy development, and community engagement.

9.8.2.2 Partnership History

In this section, the electrical corporation must provide a history of the vegetation management partnership including how long the electrical corporation has been working with the partnering agency/organization, the number of projects completed or in-progress, the scope of completed and in-progress projects (e.g., acres treated, trees planted, etc.), and the electrical corporation's quantitative contribution to the project (e.g. dollars contributed, number of workers provided, number of hours of consultation).

SCE was part of initially funding the creation of the Cal Poly WUI Fire Institute, contributing $1M over 3 years (2021, 2022 & 2023). This contribution created funding to hire an Executive Director to lead the Institute and fund research for the original methodology and utility requirements for pole clearances, and fuels management in California State Codes and Regulations.

9.8.2.3 Future Projects

In this section, the electrical corporation must provide a description of projects with the partnering agency/organization that are currently planned for the three years of the WMP cycle, have not yet begun, and are fully funded. This description must include the scope of future projects (e.g., acres treated, trees planted, etc.), projected completion years, and the electrical corporation's quantitative contribution to the project (e.g. dollars contributed, number of workers provided, number of hours of consultation).

SCE continues to participate quarterly in the Cal Poly WUI Fire Institute Advisory Council. The Advisory Council meets quarterly to advise on strategic direction and participate in specific research projects as appropriate.

9.8.3 Educational Institution Partnership (San Bernardino Community College District)9.8.4

9.8.3.1 Overview

In this section, the electrical corporation must provide an overview of the vegetation management partnership including status of the partnership (current, future, or discontinued) and a description of the type of work accomplished through this partnership. This overview must describe where the work accomplished through this partnership takes place (e.g., service territory, HFTD only, a specific county, etc.). If available, provide a link to any website associated with the partnership.

SCE partners with San Bernardino Community College (SBCC) to help develop course material specific to utility vegetation management and wildfire prevention. SCE advised in the development of course material to align with utility arboriculture and promote a consistent standard. SCE does not control the distribution of the course material but can use it at no cost. This material is intended to be shared internally, as well as with SCE contractors, with the intent of strengthening the workforce and helping individuals achieve professional goals.

9.8.3.2 Partnership History

In this section, the electrical corporation must provide a history of the vegetation management partnership including how long the electrical corporation has been working with the partnering agency/organization, the number of projects completed or in-progress, the scope of completed and in-progress projects (e.g., acres treated, trees planted, etc.), and the electrical corporation's quantitative contribution to the project (e.g. dollars contributed, number of workers provided, number of hours of consultation).

Since 2022, SCE has partnered with SBCC to develop course materials for the California Conservation Corps Arborist Training Program. In 2022–2024, SCE routinely met with SBCC for this effort.

9.8.3.3 Future Projects

In this section, the electrical corporation must provide a description of projects with the partnering agency/organization that are currently planned for the three years of the WMP cycle, have not yet begun, and are fully funded. This description must include the scope of future projects (e.g., acres treated, trees planted, etc.), projected completion years, and the electrical corporation's quantitative contribution to the project (e.g. dollars contributed, number of workers provided, number of hours of consultation).

SCE intends to continue developing and expanding the program with additional course material that is beneficial to both SCE and its contractors. SCE will continue contributing consultation time to this effort.

9.8.4 USFS Region 5

9.8.4.1 Overview

In this section, the electrical corporation must provide an overview of the vegetation management partnership including status of the partnership (current, future, or discontinued) and a description of the type of work accomplished through this partnership. This overview must describe where the work accomplished through this partnership takes place (e.g., service territory, HFTD only, a specific county, etc.). If available, provide a link to any website associated with the partnership.

SCE's engagement with USFS Region 5 (which includes SCE's service territory) focuses on reducing wildfire risks and enhancing grid resilience in forested areas. Together, we collaborate on vegetation management, wildfire prevention efforts, and the development of rapid response protocols during fire events. This partnership supports the safe delivery of electricity while protecting natural resources and communities from wildfire threats.

9.8.4.2 Partnership History

In this section, the electrical corporation must provide a history of the vegetation management partnership including how long the electrical corporation has been working with the partnering agency/organization, the number of projects completed or in-progress, the scope of completed ` and in-progress projects (e.g., acres treated, trees planted, etc.), and the electrical corporation's quantitative contribution to the project (e.g. dollars contributed, number of workers provided, number of hours of consultation).

The partnership between SCE and USFS Region 5 has evolved over time, driven by a shared goal of balancing reliable energy delivery with wildfire risk reduction. Initially focused on ROW maintenance and vegetation management in national forests, the collaboration expanded as wildfire threats intensified due to climate change, drought, and increased development in wildland-urban interface areas. SCE continues to hold monthly meetings with USFS Region 5, as feasible.

9.8.4.3 Future Projects

In this section, the electrical corporation must provide a description of projects with the partnering agency/organization that are currently planned for the three years of the WMP cycle, have not yet begun, and are fully funded. This description must include the scope of future projects (e.g., acres treated, trees planted, etc.), projected completion years, and the electrical corporation's quantitative contribution to the project (e.g. dollars contributed, number of workers provided, number of hours of consultation).

SCE is engaged in wildfire risk reduction activities with USFS Region 5 and targets the needs of the individual forests. Future projects with the USFS focus on strengthening our communications around upcoming projects, and better forecasting future workloads. SCE anticipates holding monthly meetings with USFS Region 5.

9.8.5 International Wildfire Risk Mitigation Consortium (IWRMC)

9.8.5.1 Overview

In this section, the electrical corporation must provide an overview of the vegetation management partnership including status of the partnership (current, future, or discontinued) and a description of the type of work accomplished through this partnership. This overview must describe where the work accomplished through this partnership takes place (e.g., service territory, HFTD only, a specific county, etc.). If available, provide a link to any website associated with the partnership.

The IWRMC establishes and facilitates a system of working and networking channels between members of the global utility community which supports ongoing sharing of data, information, technology, and practices to proactively address wildfire issues through learning, innovation, analysis, assessment, and collaboration. The IWRMC is led by a Utility Executive Steering Group, whose members are on the frontlines of the wildfire and bushfire issues in Australia and California. The IWRMC is comprised of four working groups: Asset Management, Risk Management, Vegetation Management, and Operations and Protocols. Working group members share experiences to help identify industry leading practices. Occasionally, members invite leading vendors to share more information on the products and services they offer to improve and expedite decision-making for those exploring similar options.

9.8.5.2 Partnership History

SCE joined with other California Investor-Owned Utilities and Australian Utilities to form the IWRMC in 2020 which created a framework for worldwide utilities to jointly combat global wildfire threats. This forum enabled SCE to connect with utilities to benchmark and share lessons learned on the strategy and execution of wildfire mitigation activities. In 2023, SCE volunteered to lead the first project, which was the study of vegetation management and hazard tree best practices. The study was completed in August 2024. SCE contributed consultation hours to this effort. SCE participates in monthly meetings as well as attending the IWRMC annual conference.

9.8.5.3 Future Projects

In this section, the electrical corporation must provide a description of projects with the partnering agency/organization that are currently planned for the three years of the WMP cycle, have not yet begun, and are fully funded. This description must include the scope of future projects (e.g., acres treated, trees planted, etc.), projected completion years, and the electrical corporation's quantitative contribution to the project (e.g. dollars contributed, number of workers provided, number of hours of consultation).

Potential future projects are discussed with IWRMC members as needed; no projects are currently planned at this time.

9.9 Activities Based on Weather Conditions

9.9.1 Overview

In this section, the electrical corporation must provide an overview of planning and execution of operational changes to address wildfire risk associated with weather conditions such as pruning or removal, executed based on and in advance of a Red Flag Warning or other forecasted weather conditions that indicates an elevated fire threat in terms of ignition likelihood and wildfire potential.

SCE identifies AOCs in its HFRA, focusing on locations that pose increased fuel- and wind-driven fire risks due to elevated dry fuel levels. The methodology used to identify AOCs are based on several factors, including fire history, weather conditions, fuel type, exposure to wind, and egress, among others. SCE inspects these AOCs during summer and fall. The AOC inspections continue to be a part of SCE's wildfire strategy, with similar areas targeted for inspection each year unless a significant event or weather conditions necessitate adjustments. In addition, SCE adjusts during Red Flag Warning periods to reduce wildfire risk and performs additional patrols during PSPS (Public Safety Power Shutoff).

9.9.2 Procedures

In this section, the electrical corporation must list applicable electrical corporation procedure(s), including the version(s) and effective date(s), used for activities based on weather conditions.

SCE's procedures for activities based on weather conditions are documented in PSPS Operations Protocol Procedure (PSPS06-TD-02), Version 8, effective March 19, 2024.

SCE's procedures for activities based on weather conditions cover a broader range of wildfire mitigation activities which include patrols to observe weather, asset, and vegetation conditions. During PSPS events, SCE performs pre-patrols, live field observations, restoration patrols and post-patrols.

9.9.3 Scheduling

In this section, the electrical corporation must describe how activities based on weather conditions are scheduled (or triggered). This must include how the schedule is affected by HFTD tier or other risk designation.

During PSPS events, Vegetation Management crews are assigned to mitigate any vegetation-related ignition risks identified during PSPS pre- or post-patrols.

SCE modifies its Vegetation Management activities during Red Flag Warning (RFW) periods to help mitigate potential risks. For example, SCE will pause non-emergency work in HFRA (e.g., use of chainsaws) that has the potential to cause sparks, and instead, work in non-HFRA areas.

SCE considers weather impacts when assigning work to contractors to inform the schedule.

9.9.4 Updates

In this section, the electrical corporation must describe changes to its activities based on weather conditions since the last WMP submission and a brief explanation as to why those changes were made. Discuss any planned improvements or updates activities based on weather conditions and the timeline for implementation.

In 2024, SCE implemented updates to IWMS models affecting AOC risk criteria, which inform decision-making processes for activities based on weather conditions. These updates to AOC risk criteria included adjustments for fuels in proximity to the Wildland Urban Interface (WUI), expansion of fuel models to represent new locations, and the introduction of a new Building Loss Factor (BLF). In 2026-2028, SCE will continue to explore updates related to AOC and activities based on weather conditions.

9.10 Post-Fire Service Restoration

9.10.1 Overview

In this section, the electrical corporation must provide an overview of vegetation management activities during post-fire service restoration.

SCE conducts post-fire patrols to identify trees that have become hazards due to fire damage. Hazardous conditions are mitigated with priority emphasis and management of debris consistent with wood and slash management procedures discussed in section 9.5.2. SCE uses internal ISA-certified arborist inspectors to assess whether a tree has a high potential to decline, or poses a significant risk to utility infrastructure, which can warrant trimming or removal.

9.10.2 Procedures

In this section, the electrical corporation must list applicable electrical corporation procedure(s), including the version(s) and effective date(s), used for post-fire service restoration vegetation management.

SCE uses its Vegetation Management Operations Storm Manual, Version 1, effective December 2024, to coordinate vegetation management activities for post-fire service restoration.

9.10.3 Scheduling

In this section, the electrical corporation must describe how post-fire service restoration vegetation management are scheduled (or triggered). This must include how the schedule is affected by HFTD tier or other risk designation.

Due to the nature of this work, there are no planned scheduling activities for post-fire restoration. Work is triggered as fire events occur within SCE's service territory. During the 2024 fire season, SCE responded to several fire events which identified and mitigated hazardous trees and vegetation.

Due to the importance of post-fire restoration for electric system safety and health, SCE collaborates with agencies and first responders to address vegetation management issues.

Clearing vegetation from roads, ROWs, and properties, is often necessary before other restoration work can begin. SCE prioritizes HFRA when performing post-fire service restorations based on objectives set forth by SCE's Incident Management Team, during an active incident.

9.10.4 Updates

In this section, the electrical corporation must describe changes to post-fire service restoration vegetation management since the last WMP submission and a brief explanation as to why those changes were made. Discuss any planned improvements or updates to post-fire service restoration and the timeline for implementation.

In 2024, SCE developed the Vegetation Management Operations Storm Manual to enable efficient mobilization and operation during a VM storm response. The manual formalizes fire restoration activities and outlines the procedures for VM Operations. Beginning in 2025, SCE will develop and deploy training for the execution of these procedures.

As part of SCE's continuous improvement efforts, updates within the vegetation work management system were refined to track damages associated with storm events and identify vegetation management mitigation, as needed. In 2024, SCE's Vegetation Management established a "Storm App" feature within the Fulcrum technology tool to track emergent work and developed several robust storm dashboards to track potential vegetation mitigation work impacted by weather conditions.

Fulcrum continues to be used for IVM and emergency response work, but SCE aims to transition record keeping to the Arbora technology tool in the future.

9.11 Quality Assurance and Quality Control

9.11.1 Overview, Objectives, and Targets

In this section, the electrical corporation must provide an overview of each of its QA and QC programs for vegetation management. This overview must include the following for each program:

- *Initiative/activity being audited (each initiative/activity name must correspond to an* initiative/activity *described in Sections 9.2 through 9.9*)
- *Tracking ID from Table 9-1 or 9-2*
- *Quality program type (QA or QC)*
- *Objective of the quality program*

Table 9-5 provides an example of the appropriate level of detail and the required format.

Table 9-5: Vegetation Management QA and QC Program Objectives

Initiative/Activity Being Audited	Tracking ID	Quality Program Type	Objective of the Quality Program
Inspections for Vegetation Clearances around Distribution Lines	VM-7	QC	To ensure vegetation inspected and/or mitigated by vegetation crews meet internal and regulatory clearance requirements.
Inspections for Vegetation Clearances around Transmission Lines	VM-8	QC	To ensure vegetation inspected and/or mitigated by vegetation crews meet internal and regulatory clearance requirements.
Hazard Tree Management Program	VM-1	QC	To verify prescribed mitigations have been completed.
Dead and Dying Tree Removal	VM-4	QC	To verify prescribed mitigations have been completed.
Compliance Structure Brushing (PRC-4292)	VM-2.2	QC	To verify compliance structures are brushed in accordance with PRC-4292 requirements. QC is only performed on PRC-4292 compliance structures.

The electrical corporation must also provide the following tabular information for each QA and QC program:

- *Initiative/activity being audited (each initiative/activity name must correspond to an initiative/activity described in Sections 9.2 through 9.9)*
- *Population/sample unit*
- *Population size for each audited initiative/activity for each year of the three-year WMP cycle*
- *Sample size for each audited initiative/activity for each year of the three-year WMP cycle*
- *Percent of sample in the HFTD for each audited initiative/activity for each year of the three-year WMP cycle*
- *Confidence level and MOE*
- *Target pass rate for each audited initiative/activity for each year of the three-year WMP cycle*

Table 9-6 provides an example of the appropriate level of detail and the required format.

Table 9-6: Vegetation Management QA and QC Program Targets[159]

Initiative/ Activity Being Audited	Population /Sample Unit	2026: Population Size	2026: Sample Size	2026: % of Sample in HFTD	2027: Population Size	2027: Sample Size	2027: % of Sample in HFTD	2028: Population Size	2028: Sample Size	2028: % of Sample in HFTD	Confidence level / MOE	2026: Pass Rate Target	2027: Pass Rate Target	2028: Pass Rate Target
Inspections for Vegetation Clearances around Distribution Lines (VM-7)	Circuit miles	9,177	6,400	100%	9,177	6,400	100%	9,177	6,400	100%	100% TRI-A 99%/3% TRI-B, C, D	100%	100%	100%
Inspections for Vegetation Clearances around Transmission Lines (VM-8)[160]	Circuit miles	~13,000	500	~50%	~13,000	500	~50%	~13,000	500	~50%	99%/5%	100%	100%	100%
Hazard Tree Management Program (VM-1)[161]	Trees	100% of trees prescribed for mitigation	100% of trees prescribed for mitigation	100%	100% of trees prescribed for mitigation	100% of trees prescribed for mitigation	100%	100% of trees prescribed for mitigation	100% of trees prescribed for mitigation	100%	100%	100%	100%	100%
Dead and Dying Tree Removal (VM-4)[162]	Trees	100% of trees prescribed for mitigation	100% of trees prescribed for mitigation	100%	100% of trees prescribed for mitigation	100% of trees prescribed for mitigation	100%	100% of trees prescribed for mitigation	100% of trees prescribed for mitigation	100%	100%	100%	100%	100%
Compliance Structure Brushing (VM – 2.2)[163]	Structures	81,000	3,958	100%	81,000	3,958	100%	81,000	3,958	100%	99%/2%	100%	100%	100%

159 Population and sample size in circuit miles is approximated and may vary based on HFRA zone remapping.
160 QC for Transmission is performed on both HFRA and non-HFRA, and QC attempts to review more HFRA than non-HFRA circuit miles.
161 The population size for HTMP QC is determined by the number of trees prescribed for mitigation resulting from the inspections. The sample size is the entire population (100%) of trees prescribed for mitigation.
162 The population size for Dead and Dying Tree Removal QC is determined by the number of trees prescribed for mitigation resulting from the inspections. The sample size is the entire population (100%) of trees prescribed for mitigation.
163 Only applies to structures in SRA which might include structures outside HFTD.

9.11.2 QA/QC Procedures

In this section, the electrical corporation must list the applicable procedure(s), including the version(s) and effective date(s), used for each vegetation management QA and QC program listed in Table 9-5.

VM QA/QC activities are addressed in procedure UVM-07, “Post Work Verification and UVM Program Oversight, Version 10, effective March 24, 2025.[164]

9.11.3 Sample Sizes

In this section, the electrical corporation must describe how it determines the sample for each QA and QC program listed in Table 9-5. This must include how HFTD tier or other risk designations affect the sampling plan, and how the electrical corporation ensures samples are representative of the population.

For Inspections for Vegetation Clearances from Distribution Lines (VM-7), VM QC sampling is performed on a circuit mile basis. SCE uses a combination of risk-based (through its TRI risk model) and judgmental sampling[165] for this activity and applies varying Confidence Levels (CL) and Confidence Intervals (CI).

SCE’s TRI risk model identifies four specific risk categories: A, B, C and D, with A being the highest risk tranche. The table below identifies the four risk categories and planned circuit miles to be inspected. 100% of Category A High Fire Risk miles will inspected, when practical, and miles within Category B, C & D will be inspected using a Confidence Level / Confidence Interval of 99/3%.

Table SCE 9-01: Distribution Circuit Mile Inspections in HFRA and State Responsibility Area (SRA)[166]

TRI Category	HFRA/SRA Circuit Miles	Total Circuit Miles	CL/CI %	Circuit Miles Inspected
A	5,134	5,134	100%	5,134
B	1,610	4,043	99/3%	1,269
C	1,105			
D	1,328			
Total	9,177		N/A	6,403

164 This procedure is included as a supporting document at https://www.sce.com/wmp.

165 Judgmental sampling is a type of non-random sample that is selected based on the opinion of an expert. Results obtained from a judgment sample are subject to some degree of bias, due to the frame and population not being identical.

166 Subject to change. Achievement of targets is subject to our ability to access the area due to environmental constraints or other restrictions.

With these risk-informed sampling volumes established, SCE performs judgmental sampling which is a type of nonrandom sample subject to some degree of bias, to determine which miles to inspect. Judgmental sampling is performed in lieu of random sampling because the sample set is not identical, and VM QC is required to verify that work performed by all VM inspection and trimming contractors meets SCE and regulatory compliance requirements. This allows for an appropriate balance of QC inspections among the contractors that perform vegetation management work.

For Inspections for Clearances from Transmission Lines (VM-8), sampling is performed on a circuit mile basis. Sampling for Transmission miles is performed using judgmental sampling and a CL/CI of 99/5%. Section 4.4 in UVM-07 provides the sampling strategy in more detail.

For VM's HTMP (VM-1) and Dead and Dying Tree Removal (VM-4), 100% QC is performed to verify that the remediation was performed.

For Structure Brushing, QC inspectors focus on Distribution structures subject to Public Resource Code 4292. QC sampling is at 99/2% CL/CI. The intent of the QC will be to confirm structures brushed meet the brushing requirements of PRC 4292.

9.11.4 Pass Rate Calculation

In this section, the electrical corporation must describe how it calculates pass rates. This description must include:

- *The sample unit that generates the pass rate for each QA and QC program (e.g., for pole clearing, the sample unit that generates the pass rate may be a single pole that passes or fails a QC audit).*

For VM-1, VM-4, VM-7 and VM-8, the sample unit is one tree that passes or fails a QC audit.

For Compliance Structure Brushing (VM-2.2), the sample unit is one structure that passes or fails a QC audit.

- *The pass and failure criteria for each program listed in table 9-5. List each criterion and discuss any weighted contributions to the pass rate.*

For VM-7 and VM-8, the criterion is achievement of regulatory clearance distance. For VM-1 and VM-4, the criterion is completion of the prescribed mitigation. For VM-2.2, the criterion is meeting the requirements of PRC 4292 brush clearance.

9.11.5 Other Metrics

In this section, the electrical corporation must list and describe the metrics used by the electrical corporation, other than pass rate, to evaluate the effectiveness of its vegetation management and inspections activities (programs) and procedures (e.g., find rate, rework rate, outage rate within 6 months of inspection attributed to vegetation contact, etc.).

SCE only uses pass (conformance) as a QC metric. However, monthly meetings are held with SCE's prime vegetation management contractors to review their overall monthly performance. SCE issues monthly "contractor scorecards" which contain metrics for

Safety, Quality (RCD, CCD, ANSI Trim Quality)[167], and Compliance (Schedule adherence, environmental compliance and invoicing timeliness). RCD compliance is trended monthly for each Prime contractor.

9.11.6 Documentation of Findings

In this section, the electrical corporation must describe how it documents its QA and QC findings and incorporates lessons learned from those findings into corrective actions, trainings, and procedures.

QC findings are entered into the vegetation work management system and tabulated using a dashboard system that identifies conformance rates by specific locations where work is performed by the specific contractor. Monthly reports are generated documenting the results of the QC inspections in addition to monthly performance review meetings where general performance is discussed in safety, quality, and compliance. Contractors not meeting acceptable quality levels may be placed on a corrective action plan if consistent under performance issues are identified. The QC inspection, review and reporting process provides a continuous learning environment. Contractor performance is tracked monthly, and corrective actions may be taken if performance drops below certain thresholds.

9.11.7 Changes to QA/QC Since Last WMP and Planned Improvements

In this section, the electrical corporation must describe:

- *A list of changes the electrical corporation made to its QA and QC procedure(s) since its last WMP submission.*

In Q2 2024, SCE formalized the QC program for Compliance Structure Brushing to provide reasonable assurance that structure brushing clearance requirements in PRC 4292 were being achieved.

- *Justification for each of the changes including references to lessons learned as applicable.*

As the QC program for Routine Line Clearing matures and inspection resources became more efficient, we were able to incorporate Structure Brushing into the QC program.

- *A list of planned future improvements and/or updates to QA and QC procedure(s) including a timeline for implementation.*

SCE continues to explore improvement opportunities in QC vegetation management programs. In the 2026–2028 timeframe, SCE plans to better assess sample sizes for each QC program and make adjustments as necessary.

167 RCD means Regulatory Clearance Distance, and is the minimum clearance required by regulation. CCD means Compliance Clearance Distance and is SCE's minimum clearance standard which is 1.5 times the RCD.

9.12 Work Orders

In this section, the electrical corporation must provide an overview of how it manages its work orders resulting from vegetation management inspections that prescribe vegetation management activities. This overview must include the following under these headers:

9.12.1 Priority Assignment

In this section, the electrical corporation must describe how work orders are assigned priority, including the activity timeline for each priority level/group.

SCE prioritizes work orders (as documented in UVM-08) based on the risk posed by observed conditions. SCE categorizes vegetation work orders as Priority 1 (P1) or Priority 2 (P2).

Priority 1: These include any observed tree or parts thereof that are expected to imminently fail and contact electric facilities, or where vegetation contact with bare-wire conductors is highly probable in high-wind or maximum load events.

Timeline: SCE mitigates Priority 1 conditions within 24 hours.

Priority 1-72 Hours: These include any P1 conditions within approximately 18 inches of the conductor in HFRA only.

Timeline: SCE mitigates Priority 1-72 Hours conditions within 72 hours

Priority 2: Priority 2 conditions are any observed tree or parts thereof that is not a Priority 1 condition and is currently stable, but the likelihood of failure and/or contact with primary electrical facilities is plausible, but not imminent. P2 conditions also include any tree prescribed for maintenance, any observed tree, or parts thereof, that is not a P1 condition but is within the Trigger Clearance Distance (TCD), Compliance Clearance Distance (CCD), or Regulatory Clearance Distance (RCD)[168] including strain or abrasion at the secondary level that is not a P1 condition.

Timeline: For Routine Line Clearing, Priority 2 conditions are mitigated based on the encroachment zone and risk score. For example, SCE remediates vegetation within the Regulatory Clearance Distance (RCD) within 30 days, subject to constraints. SCE remediates vegetation greater than the RCD but within the Trigger Clearance Distance (TCD) within 90 days, subject to constraints.

For Hazard Tree Management and Dead and Dying Tree P2 conditions, SCE typically remediates within 180 days contingent on having appropriate access and authorization to perform the mitigation.

The above internal timelines may be impacted and/or extended by various constraints. SCE remediates all P1 and P2 conditions in accordance with internal timelines identified in procedure UVM-08, "Managing Vegetation Threats."

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168 See UVM-02 Transmission Vegetation Management Plan (TVMP) and UVM-03 Distribution Vegetation Management Plan (DVMP) in Supporting Docs. RCD means Regulatory Clearance Distance, and is the minimum clearance required by regulation. CCD means Compliance Clearance Distance and is SCE's minimum clearance standard which is 1.5 times the RCD. TCD means Trigger Clearance Distance. TCD is derived from CCD plus 3 feet and is the distance that triggers the maintenance activity. GRCD is the Grid Resiliency Clearance Distance, which aligns with the GO95 Rule 35, Appendix E recommended clearance.

SCE's mitigation timelines are more restrictive than remediation timelines referenced in GO95 Rule 18A. Remediation times are also subject to constraints which may impact completion of remediation within internal timeframes. Constraints that can impact remediation include but may not be limited to: access, authorization, scheduling, resources, customer refusals, environmental (nesting birds, protected species habitat, archeological sites, cultural sites, human remains/criminal investigation), safety concerns, outage coordination, weather (flood, fire, snow, wind), permitting (City, County, State, Federal), and technological. Constraints, when practical, are documented in the vegetation work management system to the extent they are specific to an individual tree or work point.

9.12.2 Backlog Elimination

In this section, the electrical corporation must describe the plan for eliminating work order backlogs (i.e., open work orders that have passed activity timelines), if applicable.

SCE prioritizes resolution of work order backlogs which may result from environmental regulatory requirements and permitting constraints, contractor performance, access issues, customer refusals and other factors. Further, SCE has implemented process improvements for monitoring contractor progress against plans, grouping, and prioritizing work. This includes weekly meetings with contractors to discuss schedule adherence and work prioritization. In 2024, for Routine Line Clearing, HTMP and Dead and Dying Tree Removal Program, SCE transitioned into a consolidated vegetation work management system to help streamline work data into one system thereby enabling improved visibility and execution of pending work. Finally, SCE has implemented more robust reporting to improve the monitoring of work order completion progress.

For Routine Line Clearing, SCE uses a risk rank calculation to prioritize work orders which include factors such as species growth rate, days elapsed since identification of the work, TRI identification, and the clearance distance at time of inspection.

For HTMP and Dead and Dying Tree Programs, SCE uses TRC for prioritization of work orders which include factors such as tree species, tree height, tree lean and direction strike potential as well as tree risk attributes (e.g., root defects, cracks, pest infestation, etc.).

To further mitigate the risks of vegetation contact, SCE monitors the progress of open work orders related to RLC that involves vegetation breaching the required compliance distance from SCE's lines by revisiting them approximately every 30 days to help ensure that they do not become imminent threats. Additionally, SCE will continue exploring improvement opportunities related to environmental review processes that impact timelines for execution of prescribed mitigations.

For example, to improve the processing of environmental permits for vegetation management work activities, SCE continues to collaborate with agencies such as the California Department of Fish & Wildlife (CDFW) and other agencies to streamline approvals. Additionally, SCE has made significant strides with the Bureau of Land Management (BLM) for a programmatic permit agreement, with approvals from the Bakersfield Field Office in place as of Q4 2024 and further approvals anticipated by 2026.

SCE also has protocols in place to address customer access issues and continuously explores opportunities to reduce constraints.

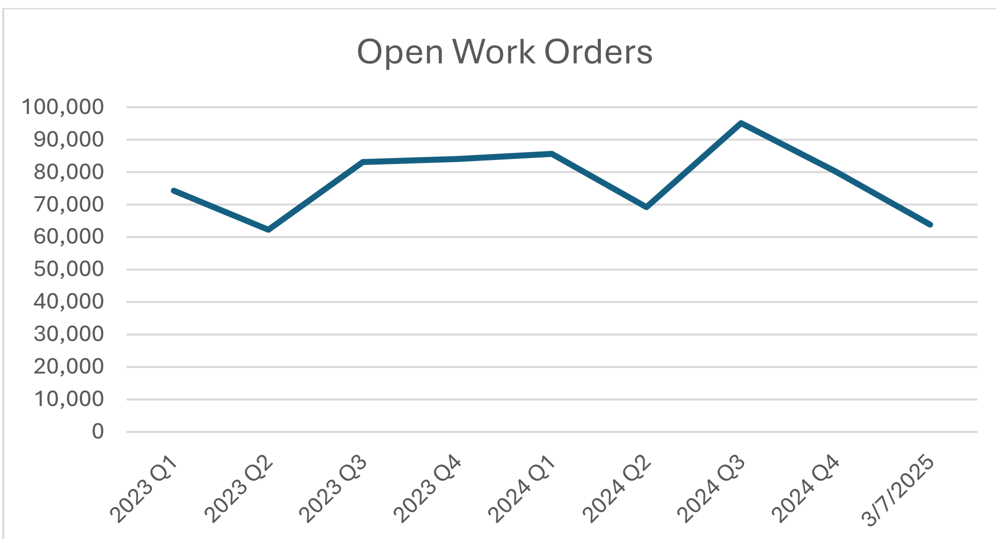
9.12.3 Trends

In this section, the electrical corporation must describe trends with respect to open work orders and:

- *An aging report for work orders past due (i.e., work orders that were not completed within the electrical corporation's assigned activity timelines per priority level/group described in Section 9.11.1) (Table 9-7 and Table 9-8) provides the required format).*

As shown in Figure SCE 9-01 and Figure SCE 9-02, the observed trends in open and past due vegetation management work orders can largely be attributed to seasonal and operational factors. Notably, the volume of work is influenced by seasonal variations, which inherently prevent a consistent, flat volume throughout the year. For example, nesting bird season is approximately from March through September and can have greater work restrictions during these months. Additionally, there is an accumulation of work orders due to other environmental holds and agency permits. These holds and permits are typically released in late Q3, resulting in a recurring trend of increased work order volume during this period each year.

Figure SCE 9-01: Volume of Open Work Orders[169]



169 As of 3/7/2025.

Figure SCE 9-02: Volume of Past Due Work Orders[170]

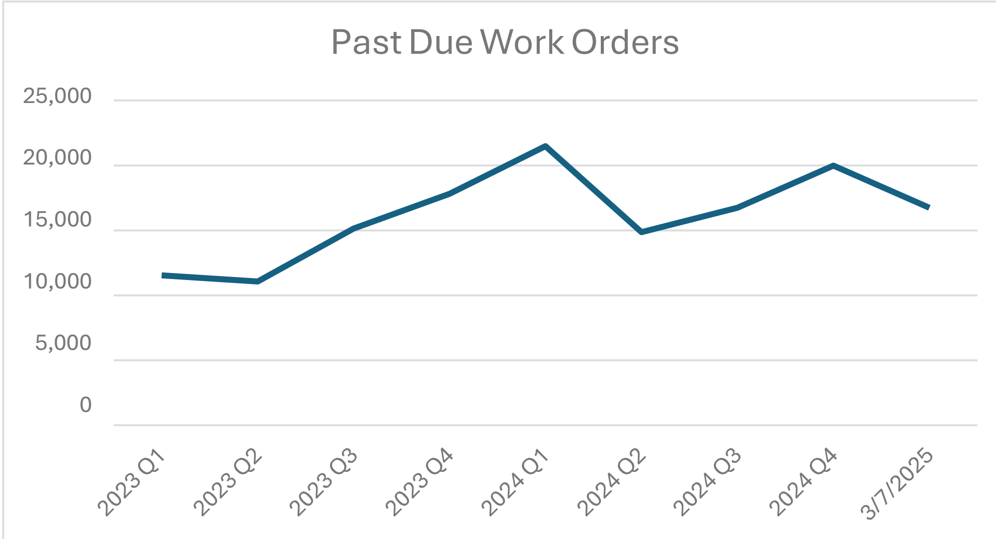


Table 9-7: Number of Past Due Vegetation Management Work Orders Categorized by Age and HFTD Tier[171]

HFTD Area	0-30 Days	31-90 Days	91-180 Days	181+ Days	Total
Non-HFTD	6,029	118	58	25	6,230
HFTD Tier 2	5,414	59	133	102	5,708
HFTD Tier 3	4,636	41	85	35	4,797
Total	16,079	218	276	162	16,735

Table 9-8: Number of Past Due Vegetation Management Work Orders Categorized by Age and Priority Levels Timeline Category[172,173]

Priority Level	0-30 Days	31-90 Days	91-180 Days	181+ Days	Total
Priority 1 (24 hours)	0	0	0	0	0
Priority 1 (72 hours)	0	0	0	0	0
Priority 2 - Less than RCD (<30 days)	1,727	55	22	2	1,806
Priority 2 - Between RCD and TCD (<90 days)	11,751	117	108	67	12,045
Priority 2 - Hazard Tree Management and Dead and Dying Tree (<180 days)	30	25	141	89	285
Strain or Abrasion on Secondary Lines[174]	N/A	N/A	N/A	N/A	N/A

170 As of 3/7/2025.
171 As of 3/7/2025.
172 The electrical corporation must use the priority levels it defines in section 9.12.1
173 As of 3/7/25.
174 Strain or Abrasion on Secondary Lines is not a formal category SCE tracks as part of its vegetation management inspections.

9.13 Workforce Planning

In this section, the electrical corporation must provide an overview of vegetation management and inspections personnel.

The electrical corporation must:

- *List all worker titles relevant to vegetation management and inspections including, but not limited to, titles related to inspecting, auditing, and tree crews*
- *List and describe minimum qualifications for each worker title with an emphasis on qualifications relevant to vegetation management*
    - *The electrical corporation must note if workers with title hold any certifications, such as being an International Society of Arboriculture Certified Arborist or a California-licensed Registered Professional Forester*

Table 9-9 provides the required format and an example of the required information.

Table 9-9: Vegetation Management Qualifications and Training

Worker Title	Minimum Qualifications for Target Role	Applicable Certifications	# of Electrical Corporation Employees with Min Quals[175]	# of Electrical Corporation Employees with Special Certifications	# of Contracted Employees with Min Quals	# of Contractor Employees with Applicable Certifications[176]	Total # of Employees	Reference to Electrical Corporation Training/Qualification Programs
Specialist	See below	N/A	10	N/A	N/A	N/A	10	See below
Senior Specialist	See below	ISA Certified Arborist	N/A	ISA Certified Arborist - 44	N/A	N/A	44	See below
Pre-Inspector	See below	N/A	N/A	N/A	169	ISA Certified Arborist - 51	220	See below
HTMP Assessor	See below	ISA Certified Arborist	N/A	N/A	N/A	ISA Certified Arborist - 90	90	See below
Lead Pre-Inspector	See below	ISA Certified Arborist	N/A	N/A	38	ISA Certified Arborist - 28	66	See below
Customer Coordinator	See below	N/A	N/A	N/A	98	ISA Certified Arborist - 17[177]	115	See below
Structure Brushing Foreman	See below	N/A	N/A	N/A	34	N/A	34	See below
General Foreman	See below	ISA Certified Arborist	N/A	N/A	72	ISA Certified Arborist -13	85	See below
Quality Control Inspector	See below	ISA Certified Arborist	N/A	N/A	4	ISA Certified Arborist - 40	44	See below
Structure Brusher	See below	N/A	N/A	N/A	167	N/A	167	See below

175 Staffing levels as of Q1 2025. This may change in the 2026-2028 timeframe.
176 SCE specifies qualifications in the contractor scope of work, these certifications are held by the contractor employees. The counts included here are a representative sample based on information collected in Q1 2025.
177 Although not required, 17 are ISA-Certified Arborists.

Specific qualifications for each position are detailed and summarized below:

- Specialist: Three (3) or more years' experience of related utility vegetation management.
- Senior Specialist: Must be an ISA-certified arborist.
- Pre-Inspector**:** One (1) year of related arboricultural/utility vegetation management experience, or two (2)-year or four (4)-year college degree in a related-field, and must be first aid/CPR certified prior to starting work.
- Lead Pre-Inspector: Classified as a level 3 or higher and may be an ISA-certified arborist;[178] it is recommended that they also obtain Tree Risk Assessment Qualifications (TRAQ)
- HTMP Assessor: Must be ISA-certified with a minimum of three (3) years of related utility vegetation management inspection and/or planning experience.
- Customer Coordinator: A minimum of two (2) years of related utility vegetation management pruning, inspection, or planning experience.
- Structure Brushing Foreman: Must have knowledge of brush clearance requirements, herbicide restrictions, and environmental requirements. Skills and abilities required for this job are comparable with those normally acquired through a high school education with extensive training and experience as a Structure Brusher.
- General Foreman: Must be an ISA-Certified arborists and/or must possess a minimum of three (3) years of related utility vegetation management pruning, inspection, or planning experience.
- Quality Control Inspector: Must have either an ISA-Certification or have a minimum of two (2) years of experience performing utility vegetation inspections and have experience measuring vegetation to conductor clearance using precision measuring tools.
- Structure Brusher: Skills and abilities required for this job are comparable with those normally acquired through a high school education with annual environmental training.

9.13.1 Recruitment

In this section, the electrical corporation must describe how it recruits vegetation management and inspections personnel, including any relevant partnerships with colleges or universities.

SCE continuously evaluates staffing levels and adjusts based on identified needs and implementation of future programs. When a staffing need is identified, these positions are typically advertised on SCE's career website and other external platforms. SCE does not

178 In certain situations, pending SCE Representative approval, a contractor may recommend a non-ISA certified arborist to perform pre-inspection supervisory functions.

have partnerships with colleges and universities for specifically recruiting vegetation management personnel.

9.13.2 Training and Retention

In this section, the electrical corporation must describe how it trains its vegetation management and inspection personnel, including any requirements for continued/refresher education and programs to improve worker qualifications.

SCE provides onboarding and annual training (Utility Vegetation Management Core Plan Training) to all vegetation management lead personnel. This training provides a detailed review of program requirements, practices, and procedures, and any updates or enhancements pertaining to SCE's vegetation management program. Typical training includes Core Plan Training reviews of the following vegetation management process documents: Transmission Vegetation Management Plan; Distribution Vegetation Management Plan; Hazard Tree Management Plan; Vegetation Threat Management; Customer Refusals; and SCE's Oversight Strategy. As it pertains to wildfire mitigation practices, this training identifies and conveys differences in inspecting and pruning practices (e.g., clearance distances) within SCE's HFRA versus non-HFRA, and identifies vegetation that may pose a risk and/or hazard to electrical facilities.

Additionally, SCE provides Environmental Awareness Orientation annually, or at the time of onboarding to all vegetation management personnel listed in Table 9-9. This Orientation includes a review of biological, wetlands/waters, and cultural/historical resources avoidance and protection, environmental compliance and requirements, and environmentally sensitive areas.

Through the minimum qualifications of the various VM roles, SCE has established the foundation of a skilled workforce. SCE continues to require the qualifications discussed above and supports the continued advancement of SCE and Contract personnel. SCE also offers a scaled contractor pay structure to encourage higher levels of worker qualifications.

As part of continuing education and improvement of the VM program, SCE updates training programs based on lessons learned. When applicable, SCE provides refresher training and communications to personnel based on updated guidelines when changes in protocols may occur during the year.

10 Situational Awareness and Forecasting

Each electrical corporation's WMP must include plans for situational awareness.

10.1 Targets

In this section, the electrical corporation must provide qualitative and quantitative targets for each year of the three-year WMP cycle. The electrical corporation must provide at least one qualitative and quantitative target for the following initiatives:

- *Environmental Monitoring Systems (Section 10.2)*
- *Grid Monitoring Systems (Section 10.3)*
- *Ignition Detection Systems (Section 10.4)*
- *Weather Forecasting (Section 10.5)*
- *Weather Station Maintenance and Calibration (Section 10.5.5)*

10.1.1 Qualitative Targets

The electrical corporation must provide qualitative targets for its three-year plan for implementing and improving its situational awareness and forecasting, including the following:

- *Identification of which initiative(s) and activity/activities in the WMP the electrical corporation is implementing to achieve the stated target, including Tracking IDs and the Tracking ID(s) used in past WMPs ("Previous Tracking ID"), if applicable.*
- *A completion date for when the electrical corporation will achieve the target.*
- *Reference(s) to the WMP section(s) or appendix, including page numbers, where the details of the target(s) are documented and substantiated.*

Required format and examples of the minimum required information are provided in Table 10-1 below.

10.1.2 Quantitative Targets

The electrical corporation must list all quantitative targets it will use to track progress on its situational awareness and forecasting in its three-year plan, broken out by each year of the WMP cycle. Electrical corporations must show progress toward completing quantitative targets in subsequent reports, including data submissions and WMP Updates. For each target, the electrical corporation must provide the following:

- *Identification of which initiative(s) and activity/activities in the WMP the electrical corporation is implementing to achieve the stated target, including Tracking IDs and the Tracking ID(s) used in past WMPs ("Previous Tracking ID"), if applicable*
- *Projected targets and totals for each of the three years of the WMP cycle, e.g., [Year 1] end of year total, [Year 2] total, and [Year 3] total, three-year total and the associated units for the targets*
- *The expected % risk reduction for each of the three years of the WMP cycle*

The electrical corporation's targets must provide enough detail to effectively inform efforts to improve the performance of the electrical corporation's situational awareness and forecasting initiatives.

Table 10-1 provides the required format and an example of the minimum acceptable level of information.

Table 10-1: Situational Awareness Targets by Year

Initiative	Quantitative or Qualitative Target	Activity (tracking ID #)	Previous Tracking ID, if applicable	Target Unit	2026 End of year total/Completion Date [1]	% risk reduction for 2026	2027 Total/Status [1]	% risk reduction for 2027	2028 Total/Status [1]	% risk reduction for 2028	Three- year total	Section; Page number
10.2 Environmental Monitoring Systems	Quantitative	Fuel Sampling (SA-17)	N/A	Fuel Samples	Take 332 fuel samples per year.	N/A [2]	Take 332 fuel samples per year.	N/A [2]	Take 332 fuel samples per year.	N/A [2]	996	10.2; p. 384
10.2 Environmental Monitoring Systems	Qualitative	Weather Station Coverage (SA-19)	N/A	N/A	Continue to maintain a map of weather station point coverage for future evaluation of potential weather station installs, if there is an identified operational need.	N/A	Continue to maintain a map of weather station point coverage for future evaluation of potential weather station installs, if there is an identified operational need.	N/A	Continue to maintain a map of weather station point coverage for future evaluation of potential weather station installs, if there is an identified operational need.	N/A	N/A	10.2; p. 384
10.3 Grid Monitoring Systems	Quantitative	Early Fault Detection (EFD) (SA-11)	SA-11	EFD installed	Install EFD at 200 locations, subject to resource/external constraints and other execution risks	0.07%	Install EFD at 200 locations, subject to resource/external constraints and other execution risks	0.09%	Install EFD at 200 locations, subject to resource/external constraints and other execution risks	0.09%	600	10.3; p. 393
10.3 Grid Monitoring Systems	Qualitative	Distribution Open Phase Detection (DOPD) (SA-14)	N/A	N/A	Evaluate DOPD integration with field area network (FAN) technology	N/A	Develop future DOPD program strategy and implementation plan based on 2026 results	N/A	Develop future DOPD program strategy and implementation plan based on 2026 and 2027 results	N/A	N/A	10.3; p. 393
10.4 Ignition Detection Systems	Quantitative	HD Camera Artificial Intelligence (AI) Uptime (SA-15)	N/A	AI uptime validation checks	Validate AI uptime on available cameras four times a year	N/A [2]	Validate AI uptime on available cameras four times a year	N/A [2]	Validate AI uptime on available cameras four times a year	N/A [2]	Validate AI uptime on available cameras 12 times	10.4; p. 407
10.4 Ignition Detection Systems	Qualitative	HD Camera Improvement (SA-18)	N/A	N/A	Develop long-term strategy to manage and identify opportunities to improve SCE's camera system	N/A	Implement long-term strategy for camera management and improvement	N/A	Implement long term-strategy for camera management and improvement	N/A	N/A	10.4; p. 407
10.5 Weather Forecasting	Quantitative	Weather Model Verification (SA-16)	N/A	Weather model verifications	Perform four weather model verifications a year	N/A [2]	Perform four weather model verifications a year	N/A [2]	Perform four weather model verifications a year	N/A [2]	Perform 12 weather model verifications	10.5; p. 414
10.5 Weather Forecasting	Qualitative	Weather and Fuels Modeling (SA-3)	SA-3	N/A	Continually evaluate and implement new weather forecast solutions, such as AI, where value may be added	N/A	Continually evaluate and implement new weather forecast solutions, such as AI, where value may be added	N/A	Continually evaluate and implement new weather forecast solutions, such as AI, where value may be added	N/A	N/A	10.5; p. 414

Initiative	Quantitative or Qualitative Target	Activity (tracking ID #)	Previous Tracking ID, if applicable	Target Unit	2026 End of year total/Completion Date [1]	% risk reduction for 2026	2027 Total/Status [1]	% risk reduction for 2027	2028 Total/Status [1]	% risk reduction for 2028	Three- year total	Section; Page number
10.5.5 Weather Station Maintenance and Calibration	Quantitative	Weather Station Calibrations (SA-12)	N/A	Weather stations calibrated	Complete 1,400 calibrations	N/A [2]	Complete 1,400 calibrations	N/A [2]	Complete 1,400 calibrations	N/A [2]	4,200	10.5.5; p. 426
10.5.5 Weather Station Maintenance and Calibration	Qualitative	Weather Station Calibration Procedures (SA-13)	N/A	N/A	Review, update, and consolidate program procedures for weather station calibration	N/A	Review and update program procedures as needed	N/A	Review and update program procedures as needed	N/A	N/A	10.5.5; p. 426

[1] The completion date for all qualitative targets is December 31, unless otherwise specified.

[2] These quantitative targets support situational awareness, but do not directly reduce outage or wildfire risk.

10.2 Environmental Monitoring Systems

The electrical corporation must describe its systems and procedures for monitoring environmental conditions within its service territory. These observations should inform the electrical corporation's near-real-time risk assessment and weather forecast validation. The electrical corporation must document the following:

- *Existing systems, technologies, and procedures*
- *How the need for additional systems is evaluated*
- *Implementation schedule for any planned additional systems*
- *How the efficacy of systems for reducing risk are monitored*

The electrical corporation must reference the Tracking ID where appropriate.

10.2.1 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. The electrical corporation must discuss systems, technologies, and procedures related to the reporting of the following:

- *Current weather conditions:*
    - *Air temperature*
    - *Relative humidity*
    - *Wind velocity (speed and direction)*
- *Fuel characteristics:*
    - *Seasonal trends in fuel moisture*

Each system must be summarized in Table 10-2. The electrical corporation must provide the following additional information for each system in the accompanying narrative:

- *Generalized location of the system / locations measured by the system (e.g., HTFD, entire service territory)*
- *Integration with the broader electrical corporation's system*
- *How measurements from the system are verified*
- *Frequency of maintenance*
- *For intermittent systems (e.g., aerial imagery, line patrols), what triggers collection. This should include flow charts and equations as appropriate.*
- *For calculated quantities, how raw measurements are converted into calculated quantities. This should include flow charts and equations as appropriate.*

Table 10-2: Environmental Monitoring Systems

System	Measurement/ Observation	Frequency	Purpose and Integration
Weather Station Coverage (SA-19)	Wind speed, wind direction, 3-second max wind gust, temperature, dew point, relative humidity, solar radiation (where applicable)	10-minutes, hourly, 24-hour (daily), 30-second reads on stations with cellular communications	Provide weather data for PSPS decision making, storm planning, storm response and restoration, energy procurement, and forecasts. Improve weather forecasts and models through data collection. Help sectionalize circuits to lesson customer impacts for PSPS de-energization
Fuel Sampling (SA-17)	Vegetation Moisture	Bi-weekly/quarterly	Assess how receptive the fuels are to fire and help align fire potential index (FPI) values when forecasts of live fuel moisture are misaligned with observations.
Live Field Observations	Supplement information from weather stations by providing real time observations of weather conditions and also identify flying debris, wire slap and other hazardous conditions that may be present at impacted area	As needed during PSPS	Qualified personnel can be deployed to high-risk portions of the grid to take live wind readings to supplement information from fixed weather stations and to watch for other inclement hazards.

10.2.1.1 Weather Station Coverage (SA-19)

Weather stations are used to provide valuable situational awareness for PSPS decision-making and help improve weather models. SCE's weather stations provide data points such as temperature measurements, wind speeds, wind direction, dew point, and relative humidity. Weather conditions can differ significantly at any given time within the HFRA of SCE's service territory, due to the territory's large size, numerous climate zones and diverse topography. For example, Southern California's mountains have rapid elevation changes and differing canyon orientations, which create localized weather zones.

SCE monitors and analyzes weather data at the circuits and circuit segments, where available, across HFRA to inform operational decisions such as deploying PSPS protocols during elevated weather conditions. Granular, circuit-level or circuit-segment-level weather data is used by incident management team (IMT) personnel to inform initiation of PSPS events, customer notifications, de-energization decisions for SCE circuits, re-energizations, as well as limiting the impact of PSPS to the extent possible to particular segments of a circuit instead of a full circuit, where applicable, dependent on circuit configurations.

To improve existing weather models and access more granular, real-time information during wildfire risk conditions, SCE has increased the number of weather stations across distribution, sub-transmission and bulk-transmission circuits in its HFRA since 2018. A higher density of weather stations allows SCE to validate real-time conditions in the field during elevated fire conditions. Adding weather stations to transmission circuits helped improve the visibility of the service territory for real-time weather monitoring, as well as improve weather forecasts along transmission circuits due to the development of machine learning forecasts using historical weather station observations for model training. Having more stations also expands and increases the granularity of data to enable improved weather forecasting capabilities at the circuit and circuit-section level.

As of January 2025, SCE has over 1,780 weather stations deployed across its HFRA, including over 160 stations on the sub-transmission and bulk-transmission system. SCE used industry equipment standards and placement techniques to capture the wind profiles of its circuits, while at times siting more than one station per circuit to account for variations in terrain, as well as circuit segmentation to minimize customer impacts.

SCE has approximately 1,450 weather stations capable of relaying 30-second, real time reads. Cellular communications are necessary for increased data collection intervals, thus satellite-only stations in remote areas (approximately 340 currently) are unable to relay data at 30-second intervals. SCE enabled 30-second reads periodically during the 2024 PSPS events in order to evaluate potential operational benefits to PSPS in real-time. SCE will continue to evaluate the operational benefits associated with 30-second reads. If operational benefits are evident, SCE will further integrate metrics associated with 30-second observations into PSPS monitoring applications.

Generalized location of the system / locations measured by the system (e.g., HTFD, entire service territory)

For SCE's weather station network, SCE prioritized weather station installations on HFRA circuits that were most likely to exceed, or had most often exceeded, PSPS wind thresholds. Not every distribution circuit in HFRA has a weather station installed, but each is in close enough proximity to have a nearby weather station assigned to provide coverage. Some circuits also required additional stations to obtain the desired level of situational awareness and/or circuit segmentation due to repeated PSPS impacts.

SCE considered the following in sequential order when prioritizing the locations of weather station installations:

- HFRA distribution circuits with historical instances of forecasts reaching PSPS criteria.[179]

- HFRA distribution circuits that previously experienced PSPS conditions and could benefit from extra weather stations for additional sectionalizing.

- Sub-transmission and transmission monitoring zones with historical instances of forecasts reaching PSPS criteria and had no representative weather stations.

- PSPS Operations subject matter experts' identification of circuits that would benefit from a weather station or an additional weather station by potentially limiting the number of customers impacted by a PSPS event by having more granular weather data available at a circuit/segment.

Once the circuit was identified, placement along the circuit depended on several factors, including, but not limited to the following:

- Location was in a wind prone area (SCE prioritized circuits in wind-prone locations where the potential consequences of a catastrophic fire were high);
- Location was easily accessible to maintenance crews;
- Location had a clear view of the southern horizon for solar power recharge purposes, as the stations are battery-powered;
- Location was free from major obstructions such as trees and buildings.

Integration with the broader electrical corporation's system

While the primary intended purposes of the weather stations installed under this initiative are to support wildfire and PSPS risk mitigation, they can and do support other secondary functions within the utility. The following are some of the other applications of weather data from weather stations:

- To forecast demand for load conditions to aid energy procurement.
- For outage forecasting to complete field work related to outages (e.g., pole replacements).
- For resource planning for storm preparations and storm responses.

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179 See https://energized.edison.com/psps-decision-making for a description of SCE's PSPS decision-making criteria.

- Inputs the weather data for its flown field conditions (i.e., the weather at the time of an aerial inspection) into its computer aided design and drafting program to help determine max-sag and max-sway.
- Uses the current and historical weather data to inform seasonal outlooks for long-term weather forecasting.
- Uses the historical data from its weather stations to aid in machine learning to enhance weather forecasting accuracy and improve the accuracy of our gridded historical dataset used to estimate weather climatology.
- To provide situational awareness for various IMTs unrelated to PSPS, which are sometimes activated during storm events where high winds, rains, thunderstorms, etc. may be present.

How measurements from the system are verified

The weather stations in the field are calibrated on an annual basis, based on field access, scheduling, and coordination with other work. These calibrations are conducted with a set of specific tools as a part of the routine maintenance.

The data collected from the weather stations is also verified by checking for outlier reads compared to nearby stations. Outlier data is identified as possibly erroneous and not recorded for historical recall.

Frequency of maintenance

The weather stations are currently maintained approximately once per year, based on field access, scheduling and coordination with other work. SCE has adopted a calibration maintenance cycle, based on weather station industry standards, see activity SA-12.

For intermittent systems (e.g., aerial imagery, line patrols), what triggers collection. This should include flow charts and equations as appropriate.

N/A; weather Stations are not considered an intermittent system.

For calculated quantities, how raw measurements are converted into calculated quantities. This should include flow charts and equations as appropriate.

N/A; weather stations are not a calculated quantity.

10.2.1.2 Fuel Sampling (SA-17)

Frequently throughout the year, it is important to view and collect vegetation moisture observations for the purpose of increasing our intra-year wildfire situational awareness. While local fire agencies conduct fuel sampling, SCE determined it would be beneficial to sample in areas where gaps exist both spatially and temporally in areas not covered by fire agencies and within its service territory.

Fuel sampling consists of physically collecting small portions of the native vegetation, which is then brought to a lab to be weighed, dried, and then weighed again to determine the vegetation's moisture content. To assure the fuel sampling program is properly managed and there is little interruption of data, SCE checks that all samples are collected and analyzed properly and resolves issues that may arise at any of the sites with the vendor as quickly as possible. This helps to ensure that the fuel sampling data is of high quality and will result in better model solutions and outputs.

SCE continuously evaluates the fuel sampling program and will make any needed adjustments to account for compromises in sampling site locations or to collect samples from additional sites in SCE's HFRA where observation gaps may still exist.

SCE's fuel sampling activity targets are provided in Table 10-1. If factors outside of SCE's control facilitate execution of additional units, SCE will strive to take 416 fuel samples per year in SCE's HFRA. This level of execution depends on exogenous factors like the site access and adverse weather.

Generalized location of the system / locations measured by the system (e.g., HTFD, entire service territory)

There are 16 fuel sampling sites within SCE's HFRA. These sites were initially selected by determining where areas could use more sampling to improve its locational fuel data, and then further refined based on SCE's right- of- way access, proximity to major roads, and the amount, type, and health of the vegetation at each location. There are three additional sites on Catalina Island that were sampled quarterly in 2024 to determine how well fuel moisture values correlate to other similar areas on the mainland.

Integration with the broader electrical corporation's system

This data is used extensively to help assess daily fire potential within HFRA and to adjust FPI calculations when needed during PSPS events.

How measurements from the system are verified

Measurements are verified by comparing the results with fuel sampling measurements performed by fire agencies.

Frequency of maintenance

Sampling is performed every two weeks for the 16 mainland sites throughout the year except when conditions are too wet from precipitation.

For intermittent systems (e.g., aerial imagery, line patrols), what triggers collection. This should include flow charts and equations as appropriate.

N/A; fuel sampling is not considered an intermittent system.

For calculated quantities, how raw measurements are converted into calculated quantities. This should include flow charts and equations as appropriate.

Live Fuel Moisture Content (LFMC) is calculated by the following equation.

Figure SCE 10-01: Live Fuel Moisture Content Calculation

$$\text{LFMC} = \frac{\text{Weight of water in the vegetation}}{\text{Dry weight of the vegetation}} \times 100$$

This formula is applied individually to each vegetation species sampled at all fuel sampling locations.

10.2.1.3 Live Field Observations

SCE trains and deploys personnel to perform line patrols and live field observations (LFOs), providing critical situational awareness during PSPS to inform decision-making.

Real-time field information during PSPS helps determine the need for just-in-time wildfire mitigation efforts, such as vegetation remediation and infrastructure repairs. In-person observations supplement data from weather stations, identifying hazards like flying debris, wire slap, and other dangerous conditions. Before re-energization, these observations help confirm that lines are clear of potential hazards. Without them, SCE would lose valuable insights, compromising informed decisions about PSPS de-energizations and re-energizations.

Line patrols and LFOs provide essential situational awareness throughout the PSPS process—before, during, and after an event. Before an event, qualified personnel (e.g., troublemen, senior patrolmen) conduct patrols using iPads to inspect assets for potential issues that high winds could worsen. During an event, personnel are deployed to high-risk areas to take live wind readings with handheld weather stations, supplementing fixed weather station data and monitoring for additional hazards. These real-time observations are relayed to SCE's Emergency Operations Center (EOC). After conditions improve, SCE dispatches personnel to perform restoration patrols on all de-energized circuits to confirm they are safe for re-energization.

These protocols are important to SCE's decision-making and will remain a key component of SCE's WMP. Even as automation and technology advance, direct field observations provide invaluable visibility into local hazards, such as swaying lines with potential wire-to-wire contact and airborne debris. Field personnel also enhance weather monitoring by supplementing fixed weather station data with portable weather readings across SCE's HFRA circuits.

Highlights since last WMP submission

Live Field Observers now use Bluetooth-enabled Kestrel wind meters. This allows them to attach the kestrel to a hot stick and take wind readings higher up from the ground, which more accurately represents the speeds that SCE assets may be experiencing. Also, this technology more efficiently and accurately logs observation data into Survey 123, which is relayed back to IMT personnel for decision making.

Generalized location of the system / locations measured by the system (e.g., HTFD, entire service territory)

Line patrols and LFOs are performed throughout the HFRA on any circuit that is in scope for PSPS consideration.

Integration with the broader electrical corporation's system

The deployment and use of Live Field Observers is limited to PSPS events and, as a result, is not integrated with daily operations on the SCE grid.

How measurements from the system are verified

N/A; this activity involves observations of weather and environmental conditions.

Frequency of maintenance

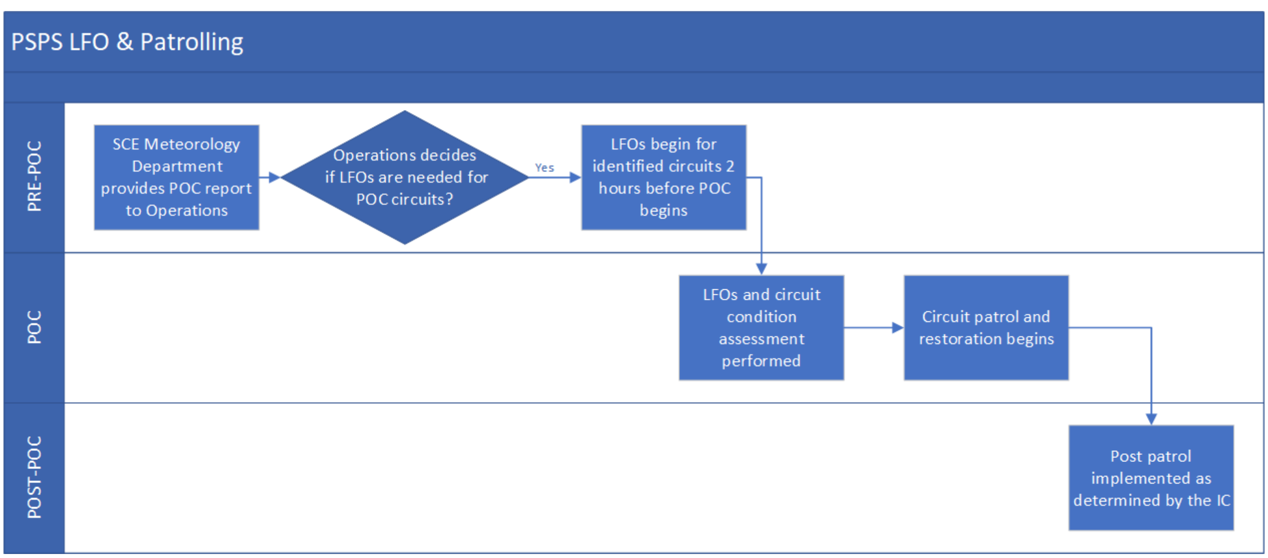
Annually, SCE delivers training to PSPS field personnel, including Live Field Observers, and briefs its contractors engaged in wildfire mitigation activities on requirements, potential impacts, and any updates to PSPS protocols since the prior year.

For intermittent systems (e.g., aerial imagery, line patrols), what triggers collection. This should include flow charts and equations as appropriate.

The type of patrols performed by field personnel on circuits that appear on the Period of Concern (POC) Report include:

- Pre-patrol: May be initiated up to five days in advance of the forecasted event.
- LFO: Patrols performed during the POC Report.
- Restoration Patrols: Performed during restoration to ensure no hazards exist before energizing circuit sections
- Post-Patrol: Performed on circuits that were not de-energized at the request of the IMT Incident Commander.

Figure SCE 10-01: PSPS LFO & Patrolling Process



For calculated quantities, how raw measurements are converted into calculated quantities. This should include flow charts and equations as appropriate.

N/A; Live Field Observations is not a calculated quantity.

10.2.2 Evaluation and Selection of New Systems

The electrical corporation must describe how it evaluates the need for additional environmental monitoring systems. This description must include:

- *How the electrical corporation evaluates the impact of new systems on reducing risk (e.g., expected quantitative improvement in weather forecasting.)*
- *How the electrical corporation evaluates the efficacy of new technologies.*

These descriptions must include flow charts as appropriate.

SCE continuously evaluates its current environmental monitoring systems for opportunities for improvement and collaborates with its vendor, Technosylva, and other academic and industry partners (e.g., SCE continues to partner with San Jose State University (SJSU) on academic research initiatives through the Wildfire Interdisciplinary Research Center (WIRC) to support projects that address California IOU efforts to reduce utility caused ignitions).

10.2.3 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*
- *Establishment of new systems*

10.2.3.1 Remote Sensing

SCE continues to implement remote sensing technology to collect additional information on weather, fuels, and fire activity to enhance SCE's wildfire modeling capabilities. Collecting this information in remote areas is challenging, which makes it necessary for SCE to continually evaluate ways to improve its situational awareness in these areas.

SCE has continued to work with the University of Colorado, Boulder to develop a Vegetation Build-Up Index, which uses remote sensing information pertaining to vegetation amount, type, and age to determine where the greatest threat for significant fire may be possible within SCE's service territory within the next three to six months. The Vegetation Build-up Index result is a heat map that shows the approximate areas where the dynamic combustibility of fuels is greatest. This product allows for an objective, quantifiable process to help identify Areas of Concern (AOCs), which are areas where inspections and potential remediations of any known issues are accelerated.

10.2.4 Evaluating Activities

The electrical corporation must describe its procedures for the ongoing evaluation of the efficacy of its environmental monitoring activity (program).

SCE continuously evaluates the efficacy of its environmental monitoring program by validating that it consistently provides essential information to aid in SCE's decision-making process. SCE's environmental monitoring systems and processes have evolved from operational decision making during PSPS events only, to being used on a daily basis to inform assessments of the service territory, fire risk, and provide situational awareness. The ongoing use and refinement of SCE's environmental monitoring systems facilitates continuous improvement. In evaluating new technologies and industry standards of the same or similar systems, SCE is able to assess and confirm efficacy due to the growth of use, and even expansion, in its various systems.

As discussed in each environmental monitoring system, SCE has developed a process to verify the measurement from the system so that SCE can rely on the information the system or process provides.

10.3 Grid Monitoring Systems

The electrical corporation must describe its systems and procedures used to monitor the operational conditions of its equipment.[89] 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*
- *How the efficacy of systems for reducing risk are monitored*

The electrical corporation must reference the Tracking ID where appropriate.

10.3.1 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*

- *Recloser operations*

Each system must be summarized in Table 10-3 below. The electrical corporation must provide the following information for each system in the accompanying narrative:

- *Location of the system / locations measured by the system*
- *Integration with the broader electrical corporation's system*
- *How measurements from the system are verified*
- *For intermittent systems (e.g., aerial imagery, line patrols), description of what triggers collection. This must include flow charts and equations where appropriate.*
- *For calculated quantities, how raw measurements are converted to calculated quantities. This must include flow charts and equations where appropriate.*

Table 10-3: Grid Operation Monitoring Systems

System	Measurement/ Observation	Frequency	Purpose and Integration
Radio Frequency Monitors	• High frequency discharges	Approximately 4.16 million samples per cycle	Identifies incipient faults before they are realized (e.g., Early Fault Detection (EFD))
Protective Relays	• Electrical current • Electrical voltage • Wave form harmonics	Minimum 4 samples per cycle; TOPD can sample at 64 samples per cycle.	Detects abnormal grid conditions such as faults, wire-downs, open phase conditions, and high impedance faults and deenergizes those circuits or circuit segments (e.g., TOPD Hi-Z, DOPD, and Fast Curve)
Smart Meters	• Electrical voltage • Electrical usage (kWh) • Meter exceptions and events (voltage thresholds that are exceeded, power off and on)	Voltage readings are in hourly intervals. Usage readings are either 15 minute or 1-hour intervals. Meter events are logged in the meter as they exceed thresholds. Meter exceptions are generated near real-time when thresholds are exceeded.	Detects energized wire-downs and other high impedance faults/hazards or identifies a failure mode of distribution transformers (e.g., MADEC, Transformer Early Damage Detection)

System	Measurement/ Observation	Frequency	Purpose and Integration
Fault Recorders	• Electrical current • Electrical voltage • Wave form harmonics	For transient records, minimum 20 samples per cycle. For long term records, minimum 4 samples per cycle.	Verifies faulted phases, fault locations and relay operation after a faulted event (e.g., Digital Fault Recorder (DFR))
Fault Current Limiters	• Electrical current • Electrical voltage	Approximately 83 samples per cycle	Detects ground fault and reduces voltage on faulted lines (e.g., REFCL)

10.3.1.1 Radio Frequency Monitors: Early Fault Detection (EFD) (SA-11)

EFD technology detects high frequency radio emissions that can occur from arcing or partial discharge conditions on the electric system. These types of conditions can indicate an incipient failure, such as severed strands on a conductor, vegetation contact, or deterioration of insulating material. Each pair of sensors can bi-angulate the detection down to a specific location.

SCE's early fault detection activity targets are provided in Table 10-1. If factors outside of SCE's control facilitate execution of additional units, SCE will strive to install up to 900 locations in SCE's HFRA over the three-year period. This level of execution depends on exogenous factors like the issuance of permits and environmental clearances.

Location of the system / locations measured by the system

In locations where EFD will be installed, SCE installs EFD sensors on every three circuit miles on distribution circuits and every five circuit miles on sub-transmission and transmission circuits. The system monitors all circuitry between sensor pairs.

Integration with the broader electrical corporation's system

EFD uses conventional cellular carriers (AT&T, T-Mobile, Verizon) and cloud service providers (Amazon Web Services) to operate and is not directly integrated with SCE systems.

Vendor-managed, standalone, cloud-based systems store EFD data for collection and analysis. This data also includes scheduling of battery replacements. SCE accesses the data via an online user interface to monitor potential degradation or defects. When EFD detects defects or degradation, SCE creates repair notifications and EFD maintenance plans in its Systems, Applications, and Products Database.

How measurements from the system are verified

SCE uses patrols and inspections to verify the conditions of assets that EFD identifies as being potentially degraded or defective.

For intermittent systems (e.g., aerial imagery, line patrols), what triggers collection. This should include flow charts and equations as appropriate.

EFD sensors are not intermittent systems. EFD sensors continually monitor the lines in locations where the sensors are deployed. If EFD detects potential fault condition, the EFD system will begin recording and reporting the data. A “detection” is either a high voltage excursion or a sample that multiple EFDs detect. SCE engineers then manually analyze EFD data. If SCE finds that the EFD technology detected a potential issue on the grid, it will notify the district, which creates a notification and repair work order for patrols and inspections to verify the condition of the asset(s) in the field.

For calculated quantities, how raw measurements are converted to calculated quantities. This should include flow charts and equations as appropriate.

EFD does not use calculated quantities.

10.3.1.2 Protective Relays: Transmission Open Phase Detection (TOPD)

TOPD technology helps reduce ignition risks associated with the high voltage transmission system by allowing high speed de-energization of an open phase (broken conductor) before it contacts a grounded object resulting in a fault event.

Open phase conditions occur when one of three phases becomes physically disconnected on the transmission system. This could occur due to a loose cable, broken conductor, or hardware/splice failure. An undetected open phase condition may cause an energized conductor to fall and potentially lead to a fault or ignition.

TOPD has two modes: (1) Alarm Mode, in which the detectors send an alert during an open phase event but will not de-energize the transmission line; and (2) Trip Mode, in which, in addition to sending an alarm, the technology will de-energize the line. Alarm mode is currently active for 28 out of 37 active TOPD installations. For 2026 and beyond, TOPD will be a part of transmission standards. Future relay installs, upgrades and replacements will follow standards for TOPD deployment, subject to standard engineering and feasibility review for individual locations.

Location of the system / locations measured by the system

In considering deployment of TOPD, SCE considers several selection criteria, including whether: (1) the transmission line traverses HFRA; (2) the line has a single conductor per phase; (3) the line is a two-terminal line; (4) presence of existing assets (e.g., relays); (5) the line has fast-clearing communication capability and can therefore be de-energized at high speeds; and (6) the line is a non-customer connected to generation, as customer facilities may require updates and face longer outages.

Integration with the broader electrical corporation’s system

The TOPD scheme provides an additional layer of protection for transmission lines and SCE integrates it into its SCE’s Energy Management System (EMS).

How measurements from the system are verified

Upon receiving a TOPD alarm, SCE analyzes any available relay oscillographs or other relevant data to determine its response. Upon identification of a loss of phase, the TOPD scheme will validate that remaining phases are continuing to operate normally (un-faulted, normal load, etc.). Following that validation, the TOPD will declare an Open Phase event by providing a local and remote alarm.

For intermittent systems (e.g., aerial imagery, line patrols), what triggers collection. This should include flow charts and equations as appropriate.

TOPD is not an intermittent system, because it operates continuously to detect conditions.

For calculated quantities, how raw measurements are converted to calculated quantities. This should include flow charts and equations as appropriate.

TOPD is armed when loading is above 13% of the primary current transformer ratio (CTR) and identifies an open phase event on the transmission line for a single conductor break. The scheme measures the primary current of a Current Transformer (CT) by measuring the secondary of the CT and then multiplying by the CTR.

$TOPD_{Arming} \geq 13\% * CTR_{Pri}$

10.3.1.3 Protective Relays: Distribution Open Phase Detection (DOPD)(SA-14)

DOPD allows de-energization of an open phase (broken conductor) before it contacts a grounded object and could result in a fault event on the distribution system. DOPD installations focus on reducing ignition risk associated with wire-down incidents by detecting and isolating for open phase events that are the result of an energized line separating.

DOPD uses a paired system between a midpoint recloser and endpoint recloser. Modern recloser controllers have the capability to be programmed for working only in alarm mode or for isolating the wire almost immediately after a qualifying open phase is detected.

Location of the system / locations measured by the system

DOPD is embedded in Distribution Recloser Controllers that protect the distribution lines residing in HFRA. Given potential integration of newer Field Area Networks (FAN), SCE is working to evaluate the optimal locations to implement DOPD using the FAN, which will provide more reliable communication between the paired reclosers.

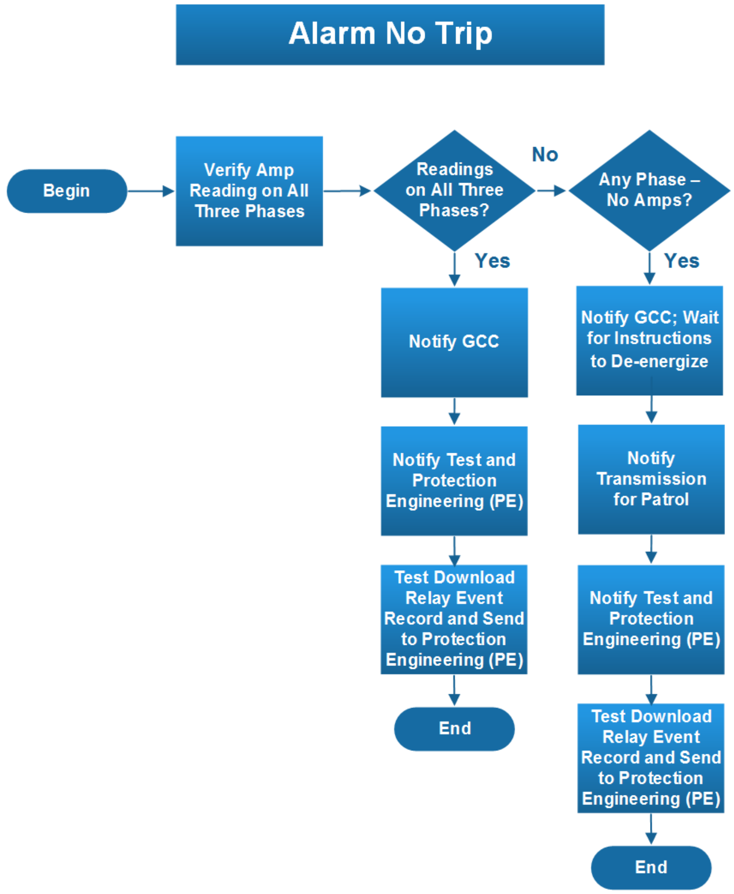
Integration with the broader electrical corporation's system

DOPD is integrated with the Distribution Management System (DMS) and provides an additional layer of protection that continuously monitors the distribution line for an open-phase event related to a hardware failure.

How measurements from the system are verified

SCE currently deploys the DOPD scheme in alarm mode. Upon receiving a DOPD alarm, SCE analyzes any available relay oscillographs or other relevant data to determine its response.

Figure SCE 10-02: Dopd Alarm Verification Process



For intermittent systems (e.g., aerial imagery, line patrols), what triggers collection. This should include flow charts and equations as appropriate.

DOPD is not an intermittent system because it operates continuously to detect conditions.

For calculated quantities, how raw measurements are converted to calculated quantities. This should include flow charts and equations as appropriate.

DOPD uses the voltage (V) and current (I) transformation signals to identify an open phase(s) event on the primary portion of the distribution circuit. The scheme measures the primary voltage of a Potential Transformer (PT) by measuring the secondary of the PT and then multiplying by the PT ratio (PTR).

Figure SCE 10-03.2: The Scheme Measures the Primary Current of a CT by Measuring the Secondary of the CT and Then Multiplying by the CTR

$$I_{Pri} = I_{Sec} * CTR$$

$$V_{Pri} = V_{Sec} * PTR$$

10.3.1.4 Protective Relays: High Impedance (Hi-Z) Relays

SCE's traditional feeder protection elements are based on overcurrent, meaning the protection elements rely on fault magnitude to trigger the relay to operate. In a high impedance (Hi-Z) event, however, the fault magnitude is small to non-existent. A Hi-Z scheme may detect arcing faults that may not be detectable by the conventional overcurrent-based schemes.

The Hi-Z algorithm can be installed on any solidly grounded distribution system.[180] Once installed, the Hi-Z settings are only able to detect high impedance conditions downstream of the field devices where the settings are installed.

SCE is evaluating and validating Hi-Z efficiency for detecting events in the field. SCE has configured Hi-Z relays to produce alarms during the pilot to understand how these operations may affect customer outages, and field testing continues to gain further knowledge on operational considerations, such as accounting for the impacts of circuit switching on Hi-Z Relay alarms.

Location of the system / locations measured by the system

Hi-Z is installed on assets (Distribution Recloser Controllers) that protect the distribution lines residing in HFRA. The Hi-Z controllers are installed at recloser controller locations protecting circuitry traversing HFRA to assess the effectiveness of detecting Hi-Z conditions. The locations were selected based on having voltage-sensors and meeting minimum required current levels (i.e., ≥ 25amps).

Integration with the broader electrical corporation's system

Hi-Z is integrated with SCE's DMS.

How measurements from the system are verified

Upon receiving a Hi-Z alarm, SCE analyzes any available relay oscillographs or other relevant data to determine its response.

For intermittent systems (e.g., aerial imagery, line patrols), what triggers collection. This should include flow charts and equations as appropriate.

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180 Solidly grounded systems are those that have a power source in which the neutral wire of the transformer or generator is directly connected to the ground.

N/A. Hi-Z is not an intermittent system.

For calculated quantities, how raw measurements are converted to calculated quantities. This should include flow charts and equations as appropriate.

Hi-Z algorithm utilizes voltage (V) and currents (I) from the primary to arm the scheme when the loading is above 5% of the primary CTR to detect for Hi-Z conditions.

$$HiZ_{Arming} \geq 5\% * CTR_{Pri}$$

$$I_{Pri} = I_{Sec} * CTR$$

$$V_{Pri} = V_{Sec} * PTR$$

10.3.1.5 Protective Relays: Fast Curves

Fast Curves provide an additional layer of protection that detects faults and operates faster than traditional relay protection to de-energize the fault circuit or circuit section to reduce the fault energy and reduce ignition risk.

Location of the system / locations measured by the system

Fast Curves use new or existing microprocessor relays on distribution lines at the station circuit breakers (CBs) or remote automatic reclosers (RARs) residing in HFRA.

Integration with the broader electrical corporation's system

Fast Curve settings are integrated with RARs and substation CBs on the system. Fast Curve integrates with and utilizes both EMS and DMS for remote enablement and disablement of Fast Curve settings.

How measurements from the system are verified

Fast Curve operation initiates an event record in the protective relay for analysis. Analyzing records after an event can identify which phases were faulted, the amount of fault current detected, and the possible location of the fault. The analysis is useful in identifying improper relay operations that can be remedied by helping field crews verify the fault source and confirm correct protection equipment operation after a fault event.

For intermittent systems (e.g., aerial imagery, line patrols), what triggers collection. This should include flow charts and equations as appropriate.

Fast Curve is not an intermittent system, as it operates continuously to detect conditions.

For calculated quantities, how raw measurements are converted to calculated quantities. This should include flow charts and equations as appropriate.

When enabled during fire weather threats, Fast Curves continuously monitor the circuit or circuit section for sudden increases in line current indicating an electrical fault and take action to deenergize the station CB or RAR to reduce the fault energy.

- Phase Fast Curve Pickup: >2.3x existing phase min trip
- Phase Delay: 4 cycles
- Ground Fast Curve Pickup: >5x existing ground min trip
- Ground Delay: 4 cycles

10.3.1.6 Smart Meters: MADEC & Transformer EDD

Meter Alarm Down Energized Conductor (MADEC) is a machine-learning (ML) algorithm that uses smart meter data to detect a subset of energized wire-downs and other high impedance faults/hazards. MADEC generates an alarm that allows SCE to act quickly and de-energize the circuit.

Transformer Early Damage Detection (Transformer EDD) utilizes meter data and a custom algorithm to proactively identify one failure mode of distribution transformers. Identified transformers are replaced before possible failure to mitigate safety hazards for the public, prevent grid disruptions, and outages.

Location of the system / locations measured by the system

MADEC and Transformer EDD are currently being used to actively monitor SCE's service territory, in locations where smart meters exist and adequate data can be collected. Each system resides on internal SCE hardware/software.

Integration with the broader electrical corporation's system

Each system uses existing collected smart data from our meter data management system and meter data warehouse. There are some integrations with SCADA to provide general MADEC alarms to prompt manual intervention to deenergize circuits.

How measurements from the system are verified

During algorithm design, historical meter data is analyzed and validated to be suitable for use cases. Additionally, various meter data are captured for further analysis as warranted.

For intermittent systems (e.g., aerial imagery, line patrols), what triggers collection. This should include flow charts and equations as appropriate.

MADEC (described in Figure SCE 10-03 below) automatically runs every minute on the available near real-time meter data, given all supporting infrastructure is available.

For Transformer EDD (described in Figure SCE 10-04 below), SCE personnel review the preliminary results since manual post-processing of results is required before trouble orders for field investigation or remediation can be created.

Figure SCE 10-03: MADEC Flowchart

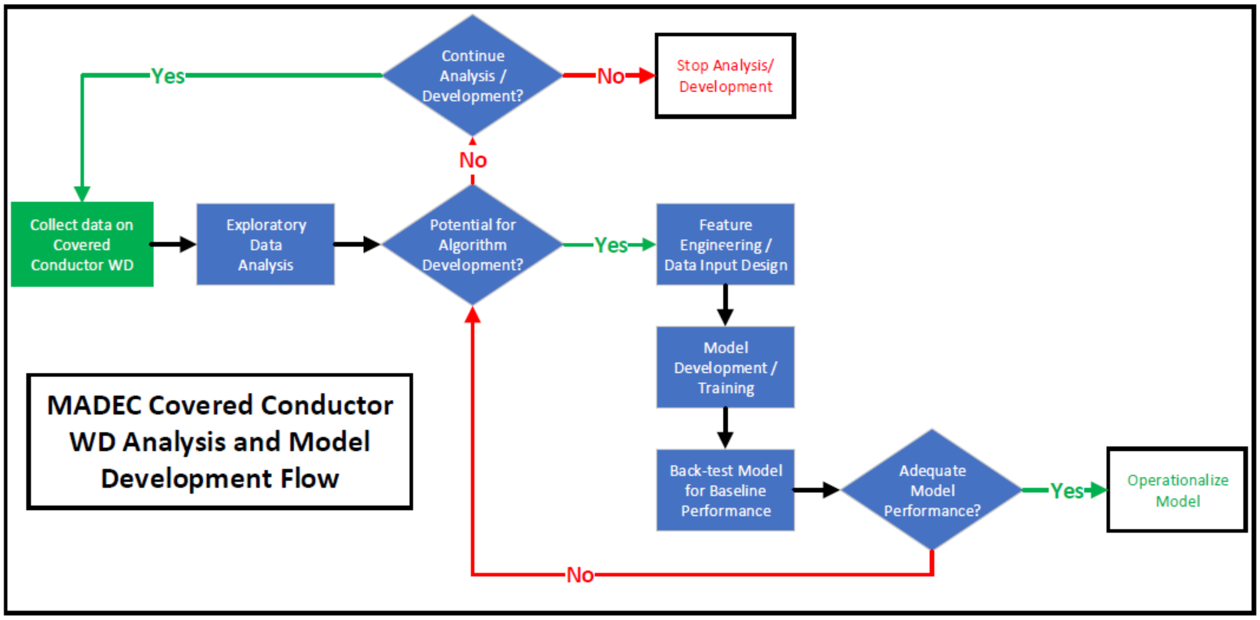
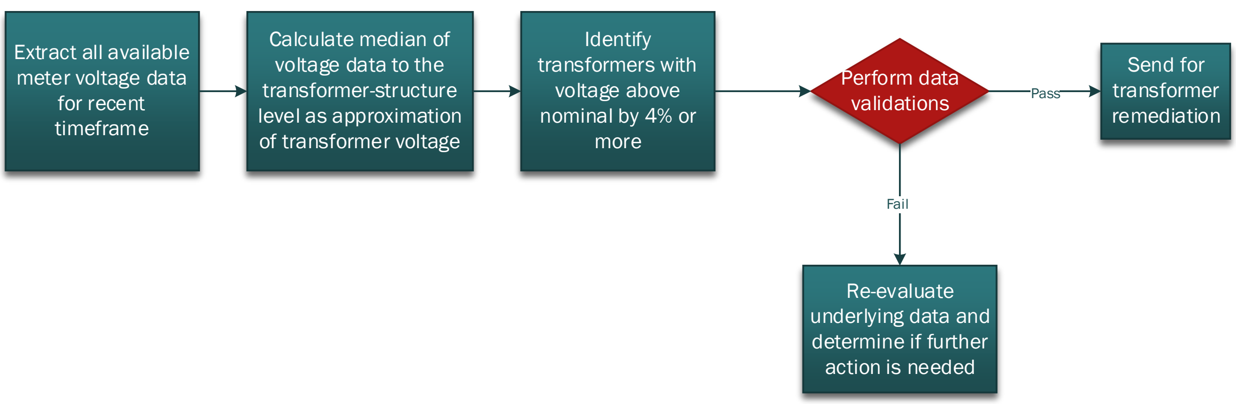


Figure SCE 10-04: Transformer EDD Flowchart



For calculated quantities, how raw measurements are converted to calculated quantities. This should include flow charts and equations as appropriate:

For MADEC, simple calculations and transformations are used to convert incoming raw data into binned values and ratios. MADEC uses internal grid connectivity data and voltage type exception information to create various downstream features for the ML model. Most of these features are used to create/calculate bins, ratios, and the timing/sequence of events and are typically aggregated to the structure or meter level.

The model itself uses a standard Gradient Boosted Trees model. Model hyperparameters are based on a historic dataset.

If a potential wire down situation is determined, the model output will identify a line with the circuit and nearby device or structures to help with locating the wire down. No output is generated if nothing is detected.

For Transformer EDD, raw meter voltage data (e.g., historic smart meter hourly voltage interval data and internal grid connectivity information) is used to calculate the list of transformer failures for remediation. The output is produced by identifying transformers with voltage (V) ≥4% above nominal, which is calculated by taking the median voltage of smart meters per transformer-structure and then comparing the calculations between neighboring transformers to understand if the transformer could have damage.

$$V_{Tranformer\ meter\ median} \geq 1.04\% * V_{Nominal}$$

10.3.1.7 Fault Recorders: Digital Fault Recorder

Digital Fault Recorders (DFRs) can be used to verify faulted phases, potential fault locations and correctness of relay operation after a faulted event, which helps with remediation of failed equipment (line or relay) to prevent reoccurrence of these events.

Location of the system / locations measured by the system

DFRs are typically located at the substation and are installed in HFRA and system-wide.

Integration with the broader electrical corporation's system

Data from the Distribution DFRs are automatically stored on the devices but needs to be retrieved from the devices manually.

How measurements from the system are verified

Data collected by the DFRs can be independently verified by other Intelligent Electronic Devices such as relays and meters.

For intermittent systems (e.g., aerial imagery, line patrols), what triggers collection. This should include flow charts and equations as appropriate.

DFRs are triggered whenever the voltage is 110% over or 10% under nominal voltage. Additionally, one ampere secondary residual current and external digital inputs are used to trigger fault recordings on the DFR at the BES.

For calculated quantities, how raw measurements are converted to calculated quantities. This should include flow charts and equations as appropriate.

The DFR provides the primary voltage of a Potential Transformer (PT) by measuring the secondary of the PT and then multiplying by the PT ratio.

$$V_{Pri} = V_{Sec} * PTR$$

The DFR provides the primary Current of a Current Transformer (CT) by measuring the secondary of the CT and then multiplying by the CT ratio.

$$I_{Pri} = I_{Sec} * CTR$$

10.3.1.8 Fault Current Limiters: (SH-17 & SH-18)

Rapid Earth Fault Current Limiters (REFCL) are an emerging Grid Hardening Technology Installation and Pilot program which is primarily discussed in Chapter 8.2.6. Please refer to that section for SCE's explanation of its REFCL programs.

Location of the system / locations measured by the system

- REFCL Ground Fault Neutralizer (GFN) and Grounding Conversion technology is located at either small or large substations. GFN is designed for large substation conversions and Grounding Conversions is designed for small substation or distribution circuit level.

Integration with the broader electrical corporation's system

This varies by REFCL projects. Typically, they are integrated at the substation or along a circuit.

How measurements from the system are verified

A digital fault recorder measures line currents and voltages for a post-fault analysis.

For intermittent systems (e.g., aerial imagery, line patrols), what triggers collection. This should include flow charts and equations as appropriate.

REFCL is not an intermittent system, as it operates continuously to detect conditions.

For calculated quantities, how raw measurements are converted to calculated quantities. This should include flow charts and equations as appropriate.

The controller for the GFN calculates many quantities. For a detailed description of the quantities calculated by REFCL systems see the workpaper titled, "Rapid Earth Fault Current Limiter (REFCL) Projects at Southern California Edison."[181]

181 Ibid.

10.3.2 Evaluation and Selection of New Systems

The electrical corporation must describe how it evaluates the need for additional grid operation monitoring systems. This description must include:

- *How the electrical corporation evaluates the impact of new systems on reducing risk (e.g., expected reduction in ignitions from failures, expected reduction in failures.)*

- *How the electrical corporation evaluates the efficacy of new technologies.*

These descriptions must include flow charts where appropriate.

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.)

SCE considers a variety of factors when identifying, implementing, and evaluating new systems. For systems in a pilot or exploratory mode, SCE typically evaluates feasibility, cost, operational issues, and efficacy (e.g., is the system correctly detecting fault conditions). For systems that are farther along and in larger scale implementation, such as REFCL, SCE may have a broader data set on which to compare results from the new system to parts of its grid that do not have the system, and thus have more field data on which to evaluate results and efficacy. Ultimately, evaluation of new or recently implemented grid monitoring systems is not a “one size fits all” approach as each system or technology needs to be evaluated on the unique criteria relevant to SCE’s initial hypothesis or intentions with piloting or testing it.

How the electrical corporation evaluates the efficacy of new technologies.

SCE evaluates the efficacy of new technologies based on the historical ignition and fault data in conjunction with subject matter expert (SME) judgement. The specific process for evaluating the technology’s efficacy at grid monitoring may vary depending on the technology. For example, the mitigation effectiveness percentages for REFCL are based on a combination of SCE testing and analysis, testing conducted in Australia, and SCE SME judgement. Other evaluations may involve using historical data, comparing geographies, or lab testing. When possible, SCE may also try to compare portions of its HFRA with and without the technology to better isolate its effects. However, this can be challenging as SCE has many years of wildfire mitigations deployed in the field, which can complicate efforts to find a true “no mitigations” baseline of data against which an additional or incremental mitigation can be evaluated.

10.3.3 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*
- *Establishment of new systems*

Below SCE describes its planned improvements for its grid operations monitoring systems. SCE has focused on the most material items, with a focus on improvements that are associated with a WMP activity target or pilot. At this time, SCE does not have plans for the establishment of new systems but may report changes in future WMP Updates.

EFD (SA-11)

SCE intends to continue this activity through the 2026-2028 WMP period. Please see Table 10-1 for its activity target.

TOPD

As discussed above, SCE has integrated TOPD into its transmission standards, and it will be installed as transmission assets are upgrade or replaced.

DOPD (SA-14)

SCE intends to continue this activity through the 2026-2028 WMP period. Please see Table 10-1 for its activity target.

Hi-Z

As discussed above, SCE intends to continue this pilot into the 2026-2028 WMP period. SCE intends to install up to 60 Hi-Z relays over the three-year period.

Fast Curves

Please see Section 8.2.8.1 for SCE's discussion of its Remote Controlled Automatic Reclosers Settings Update (SH-5) program, and Table 8-1 for the activity target for that program. SH-5 represents SCE's efforts to install devices that support Fast Curve settings.

REFCL (SH-17 & SH-18)

Please see Table 8-1 for SCE's activity targets for its two REFCL programs.

10.3.4 Evaluating Activities

The electrical corporation must describe its procedures for the ongoing evaluation of the efficacy of its grid operation monitoring activity (program).

Please see the discussion above in Section 10.3.2. Additionally, SCE monitors the efficacy of its mitigations by performing engineering reviews of ignitions involving SCE facilities through the Fire Investigation Preliminary Analysis (FIPA) process. The FIPA process examines ignitions to determine:

- Cause
- Contributing Factors
- Involved Equipment
- Deployed Mitigation in the area

SCE monitors the data derived from its FIPA process and other pieces of information, such as outages and wire downs, to ensure SCE's programs are performing as desired. If an engineer in the FIPA process notices an event where mitigations did not perform as expected, the engineer will escalate the issue and the team will discuss whether changes to SCE's standards or policies are needed to correct any issues.

Additionally, SCE will periodically supplement its FIPA analysis by reviewing fault data, repair notification and wire downs to evaluate whether the grid monitoring mitigations are operating as intended. In addition, SCE will periodically review other fault data not captured in the FIPA process to evaluate whether the grid monitoring mitigations are operating as intended.

10.4 Ignition Detection Systems

The electrical corporation must describe its systems, technologies, and procedures used to detect ignitions within its service territory and gauge ignition size and growth rates.

The electrical corporation must document the following:

- *Existing ignition detection sensors and systems*
- *Evaluation and selection of new ignition detection systems*
- *Planned integration of new ignition detection technologies*
- *Identify any systems, technologies, and procedures for routine sharing of the following:*
    - *Evaluation of strengths and limitations of new technology*

- *Case studies/ lessons learned regarding new ignition detection systems and new ignition detection technologies*
- *Lessons learned*

- *Monitoring of initiative improvements*

The electrical corporation must reference the Tracking ID where appropriate.

10.4.1 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*
    - *Infrared cameras*
- *Fire growth potential software*

The electrical corporation must summarize each system in Table 10-4 below. It must provide the following additional information for each system in an accompanying narrative:

- *General location of detection sensors (e.g., HFTD or entire service territory)*
- *Resiliency of sensor communication pathways*
- *Integration of sensor data into machine learning or AI software*
- *Role of sensor data in risk response*
- *False positives filtering*
- *Time between detection and confirmation*
- *Security measures for network-based sensors*

While SCE is not a fire suppression agency, it does maintain various technologies and systems that can help confirm ignition and gauge their size and/or growth rates. These tools help to monitor and evaluate weather and climate conditions for the purpose of understanding ignition potential and consequence, which informs a range of short-and long-term mitigations such as PSPS, inspections, and grid hardening. As such, SCE summarizes each of its applicable systems in the table below.

Table 10-4: Fire Detection Systems Currently Deployed

Detection System	**Capabilities**	**Companion Technologies**	**Contribution to Fire Detection and Confirmation**
HD Cameras (SA-15)	Real-time viewing of remote areas to confirm smoke and wildfires	Used with AI as well as satellite imagery for fire confirmation	SCE partners with University of California, San Diego (UCSD) to install HD cameras on non-SCE infrastructure, such as a communications towers, in locations where its Fire Science Team, Fire Management Team, IMT and/or fire agencies have previously identified gaps in the spatial data related to ignition confirmation.
Satellite & Other Imaging Technology	Resolve gaps in SCE's spatial data and provide improved fire confirmation capabilities.	Used with HD cameras for fire confirmation	Satellite & Other Imaging fire confirmation will be used with the current fire confirmation capabilities provided by UCSD. The Satellite detection will provide full coverage of the SCE territory and work as tool to help confirm fires on the HD camera system.

Additional information for each of its systems is detailed below.

10.4.1.1 HD Cameras (SA-15)

HD camera installations provide improved fire confirmation capabilities. To support situational awareness with respect to fuel conditions, help inform PSPS decision-making, and provide the ability to confirm smoke and/or fire in a location via AI, SCE maintains a network of 200 HD cameras installed through the UCSD's ALERTCalifornia program. The live data feeds aid in faster information gathering for fire location and possible direction of growth. This information is valuable for SCE asset protection as well as for fire departments to assess resource deployment.

The HD cameras provide SCE a more timely response for situational awareness and asset protection from fires than would otherwise be possible. The HD cameras also supplement fire response efforts and coordination with fire response agencies.

Highlight any improvements made since the last WMP submission

In partnership with UCSD, SCE now has full access to AI that uses the camera data feeds to alert a specific camera location so personnel can better assess real-time conditions of a fire (i.e., location, growth potential, nearby SCE assets, possible communities in danger, fire department resource deployment). The primary goal of the AI remains for fire agencies to subscribe to alerts in their respective areas for greater situational awareness in fighting fires. An ancillary benefit for SCE as the camera sponsor is to be informed of confirmed fires in or around our infrastructure to assist with asset protection.

General location of detection sensors (e.g., HFTD or entire service territory)

SCE partners with UCSD to install HD cameras in locations where its Fire Science Team, Fire Management Team, IMT and/or fire agencies provide insight for rural areas needing viewshed to assist in confirming the start of a fire. UCSD installs on towers of opportunity in these remote locations, such as shared communication towers, wireless internet provider towers or county-owned communication towers. Cameras are not installed on SCE-owned infrastructure. The number and location of future installations will be based on requests on an as-needed basis by SCE's Fire Science, Fire Management, IMT teams or in conjunction with fire agencies.

Resiliency of sensor communication pathways

The HD camera communication pathways are provided through UCSD. UCSD secures network connections through wireless internet service providers, which are available at the location of installation. Not every camera is on the same communication path network. UCSD monitors the connectivity and is responsible for connectivity maintenance and any necessary break fixes. UCSD allows SCE access to the HD camera status page in order to view the connectivity status.

Integration of sensor data into machine learning or AI software

SCE has partnered with UCSD to obtain access to AI software running on ALERTCalifornia cameras. SCE and fire agencies within its service territory area receive alerts from ALERTCalifornia that identify what camera spotted the anomaly, confirms the fire is present, and provides the fire's general location.

SCE validates AI uptime on available cameras throughout the year. The AI is how SCE and fire departments are alerted to potential fire start locations. With these notifications, SCE can identify potential infrastructure for any necessary asset protection, and fire agencies can help determine location and appropriate fire response. Ensuring the capability is operational and running is key for advanced notice of possible fires.

Role of sensor data in risk response

The live feeds that are provided from the cameras provide direct indication for wildfire conditions and ignition propagation. These confirmation capabilities are enhanced through the use of AI, which sends alerts to fire agencies to inform of early-stage ignitions. The confirmation capabilities and AI alerts provide situational awareness to better inform decision making post ignition.

False positives filtering

Upon receiving notifications, SCE personnel view for situational awareness and decide if an alert needs to be investigated or any further actions taken. Among the alerts, false positives are seen where further action is not needed and the alert is dismissed.

Time between detection and confirmation

AI is used primarily to confirm the existence of a fire. SCE does not use the AI to detect fire starts; therefore, SCE does not track time stamping of the alert notifications. The AI will alert of a potential fire or a confirmed fire.

Security measures for network-based sensors

SCE relies on UCSD to keep the data feeds secure. SCE accesses the cameras through the publicly available, vendor provided website, https://ops.alertcalifornia.org/.

10.4.1.2 Satellite Imaging Technology

Satellite imaging technology is used to help confirm the ignition origin and perform threat assessments, among other information, that can be derived from having an overhead or aerial view of the fires. SCE works with UCSD, who has integrated this technology into their situational awareness platform, to confirm and follow changes in fire locations and the spread of a fire through ALERTCalifornia. SCE created a map on its website for customers to view fire detection from public satellites along with fire perimeters from local fire agencies, which includes weather station observation from the National Weather Service.[182] This SCE website provides customers and other stakeholders with increased situational awareness.

General location of detection sensors (e.g., HFTD or entire service territory).

The technology produces an output that covers the entire SCE service territory.

Resiliency of sensor communication pathways

182 See https://www.sce.com/wildfire/situational-awareness

Communication pathways are controlled by the National Oceanic and Atmospheric Administration (NOAA) and National Aeronautics and Space Administration (NASA) because this is a government-owned satellite system.

Integration of sensor data into machine learning or AI software

Satellite fire confirmation capability has been integrated in the current fire conformation technology provided by UCSD and used by SCE. This service will add additional notification and confirmation abilities.

Role of sensor data in risk response

Sensors provide increased coverage for wildfire detection within the SCE service territory. This increases the ability to reduce risk by increasing fire conformation coverage capabilities across the SCE territory.

False positives filtering

False positives are filtered out by the algorithm that will provide the alert of a possible wildfire. False positives will still occur as this is a new technology being used within SCE. The AI software for the HD cameras will be used for fire conformation.

Time between detection and confirmation

Satellite & Other Imaging will be used primarily to confirm or track the existence of a fire by SCE or local fire agencies. SCE will not use the Satellite & Other Imaging to detect fires therefore SCE will not track detection and confirmation. Fire confirmation will depend on the geographic location of the detection and view shed of any existing alert wildfire camera to confirm this detection. Some detections will not be within the view of the cameras and will need to be confirmed by local fire agencies.

Security measures for network-based sensors

Sensors from the satellite detection are operated and managed by NOAA's National Environmental Satellite, Data, and Information Service division. No sensor will be placed within the SCE network, system or assets.

10.4.2 Evaluation and Selection of New Detection Systems

The electrical corporation must describe how it evaluates the need for additional ignition detection technologies. This description must include:

- *How the electrical corporation evaluates the impact on new detection technologies on reducing and improving detection and response times.*
- *How the electrical corporation evaluates the efficacy of new technologies.*
- *The electrical corporation's budgeting process for new detection system purchases.*

SCE consults with external agencies, such as fire agencies, to determine additional fire confirmation technology needs. As discussed in Section 10.4.1, SCE partners with other entities for its fire confirmation systems and capabilities, such as UCSD's ALERTCalifornia system and NOAA and NASA's satellite system. Any needs identified by SCE or fire agencies are reviewed and approved collaboratively. In 2026, SCE will develop a long-term strategy to manage and identify opportunities to improve SCE's camera system.

How the electrical corporation evaluates the impact on new detection technologies on reducing and improving detection and response times.

SCE evaluates the impact of new ignition detection technologies by first proving out the use case for the technology with small case studies or limited deployment of the system or technology. SCE then assesses the new technology or system to see if there are quantifiable impacts on its or fire agencies' abilities to confirm ignitions. SCE notes that it is not a fire suppression agency and therefore focuses efforts on methods to support customer safety, grid resiliency, and the ability for fire suppression agencies to respond to wildfires.

How the electrical corporation evaluates the efficacy of new technologies

SCE evaluates the efficacy of new ignition confirmation technology by, as described above, assessing if it is useful for fire mitigation efforts and to inform analyses of the service territory, fire risk, and provide situational awareness, in addition to operational decision making, including but not limited to PSPS. In addition to the assessment described above, SCE also consults with fire agencies for their own assessments of the efficacy of new technologies.

The electrical corporation's budgeting process for new detection system purchases

As indicated above, SCE partners with external agencies to determine additional ignition confirmation needs. Once a need is identified and confirmed, SCE's share of the cost is reviewed and approved by SCE's internal approval process, which includes review by a variety of stakeholders, such as SCE's wildfire strategy and enterprise risk management groups, in addition to senior management.

10.4.3 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*
- *Increases in budgets and staffing to support new systems*

Currently, SCE does not have any definitive plans to integrate new ignition detection technologies. That may change as SCE completes its long-term strategy to manage and identify opportunities to improve SCE's camera system.

10.4.4 Evaluating Activities

The electrical corporation must describe its procedures for the ongoing evaluation of the efficacy of its fire detection systems.

SCE's procedures for the ongoing evaluation of the efficacy of its ignition confirmation technologies include reviewing how HD cameras and Satellite & Other Imaging technology are used and that its fire spread modeling provides essential information to aide in SCE's decision-making process.

SCE evaluates the efficacy of HD cameras and Satellite & Other Imaging based on the amount of usage of SCE networks, feedback from the SCE Fire Management Team, the integration of the system into CAL FIRE's operations, and feedback from other firefighting agencies. SCE's ignition confirmation systems and processes are useful for fire mitigation efforts and to inform assessments of the service territory, fire risk, and provide situational awareness. Crucially, they also help guide operational decision making, including but not limited to PSPS.

The HD cameras and satellite imaging technology are viewed on a near daily basis by SCE Fire Science and SCE Fire Management Officers. Multiple fire agencies also routinely use the cameras and have provided positive feedback to SCE's Fire Management Officers and UCSD. Efficacy can also be determined by the expansion of the ALERTCalifornia system. The camera network has undergone user interface improvements, the integration of AI, and the continued installation of cameras across California by a multitude of agencies in addition to SCE. The growth of the camera network platform and Satellite & Other Imaging technology helps to validate the efficacy of these technologies and confirm they are fulfilling their intended purpose.

SCE's ignition confirmation systems provide essential information to aid in fire mitigation efforts, but do not directly influence wildfire risk drivers. For example, HD cameras have proven useful in fire mitigation efforts by providing live views of fires for fire management officers to use for situational awareness. SCE fire management officers heavily rely on the HD cameras and are one of the most frequent users of the network. SCE fire management officers can view the proximity of a fire to SCE infrastructure and help direct asset protection efforts. Fire departments also use the HD cameras to help identify and confirm smoke, fire location, size of fire, direction of fire, direct response efforts, possible growth, and other potential fire aspects.

10.5 Weather Forecasting

The electrical corporation must describe its systems and procedures used to forecast weather within its service territory. These forecasts must inform the electrical corporation's near- real-time-risk assessment and PSPS decision-making processes. The electrical corporation must document the following:

- *Its existing modeling approach*
- *The known limitations of its existing approach*
- *Implementation schedule for any planned changes to the system*
- *How the efficacy of systems for reducing risk are monitored*

The electrical corporation must reference the Tracking ID where appropriate.

10.5.1 Existing Modeling Approach

At a minimum, the electrical corporation must discuss the following components of weather forecasting:

- ***Data assimilation** from environmental monitoring systems within the electrical corporation service territory*
- ***Ensemble forecasting** with control forecast and perturbations*
- ***Model inputs**, including, for example:*
    - *Land cover / land use type*
    - *Local topography*
- ***Model outputs**, including, for example:*
    - *Air temperature*
    - *Barometric pressure*
    - *Relative humidity*
    - *Wind velocity (speed and direction)*
    - *Solar radiation*
    - *Rainfall duration and amount*
- ***Separate modules** (e.g., local weather analysis and local vegetation analysis)*
- ***Subject matter expert (SME) assessment of forecasts***
- ***Spatial granularity of forecasts**, including:*
    - *Horizontal resolution*

- *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

SCE uses new weather forecast information from in-house model systems and public weather data from vendors at a frequency of up to hourly. SCE's in-house models are generated by downscaling initial conditions provided by various government agencies twice per day. Additionally, meteorologists consult rapidly updating forecasts (known as nowcasting) from the High Resolution Rapid Refresh (HRRR) model that is generated every hour by the National Centers for Environmental Prediction (NCEP). SCE weather station observations are also shared into the Meteorological Assimilation Data Ingest (MADIS) system used by the National Weather Service to integrate observations into their models that are received by SCE.

Ensemble Forecasting

SCE creates an ensemble forecast consisting of 18 individual Weather Research and Forecasting (WRF) model solutions. The ensemble members are developed by using multiple model initial and boundary conditions sources, multiple physics parameterization choices, and multiple grid lengths. Physics parameterization selections within the control and ensemble models are listed in the table below. Initial and boundary conditions for the ensemble models are provided by the NCEP Global Forecast System (GFS), NCEP North American Mesoscale Model (NAM), and the European Centre for Medium-range Weather Forecasts (ECMWF) Integrated Forecast System (IFS; i.e., European Global Weather Model).

The control model is initialized using the GFS. Model grid length is described later in this section. More detail on the physics choices can be found in the WRF users guide published by the National Center for Atmospheric Research https://www2.mmm.ucar.edu/wrf/users/docs/user_guide_v4/.

Table SCE 10-01: Summary of WRF Model Physics Configurations

Physics Parameterization Selections	Control Model (Deterministic WRF)	Ensemble Perturbations
Cloud Physics	Morrison	Morrison, New Thompson, Eta
Boundary Layer Physics	MYNN3	MYNN, MYNN3, YSU, Shin-hong, MYNN2.5
Surface Layer Physics	MYNN	MYNN, Revised MM5
Shortwave Radiation	New Goddard	New Goddard, RTTMG, CAM
Longwave Radiation	New Goddard	New Goddard, RTTMG, CAM
Land Surface Model	NoahMP	NoahMP

Model Inputs

The following are inputs of SCE's weather and fuels modeling

- Operational and historical Weather Research and Forecasting Model Inputs
- Operational forecast models are driven by upper-level weather conditions, surface weather conditions from the GFS, NAM, and ECMWF initial and boundary conditions with soil moisture estimates from the NASA SPoRT dataset.
- Historical reanalysis data is initialized from the NCEP Climate Forecast System Reanalysis
- Operational Nowcasting (very short-term forecast) Inputs
- NCEP HRRR model.
- Machine Learning
- Multiple fields from the control WRF model including:
- Surface wind speed
- Surface wind direction
- Surface dew point temperature
- Friction velocity (a measure of the degree of turbulence and mixing)
- Terrain roughness
- Surface temperature gradient
- Surface wind speed gradient

Wind speed (at 500 m, 1000 m, and 1500 m above ground level (AGL))

- Wind direction (at 500 m, 1000 m, and 1500 m AGL)
- Temperature (at 500 m, 1000 m, and 1500 m AGL)

- Multiple fields from the ensemble WRF models including: Ensemble max, mean, percentiles (25th and 75th) and standard deviation of surface wind speed from 10 different ensemble members
- Ensemble max, min, mean, percentiles and standard deviation of temperature
- Ensemble max, min, mean, percentiles and standard deviation of dew point
- Ensemble mean, percentiles and standard deviation of friction velocity (a measure of the degree of turbulence and mixing)
- Terrain roughness
- Ensemble mean of surface temperature gradient
- Ensemble mean of surface wind speed gradient
- Ensemble mean of wind speed (at 500m, 1000m and 1500m above ground level (AGL))
- Ensemble mean of sin and cos of the wind direction (at 500m, 1000m and 15000m AGL)
- Ensemble mean of temperature (at 500m, 1000m and 15000m AGL)
- Multiple fields from the NCEP NAM (public weather model data):
- Surface wind speed
- Surface wind gust speed
- Surface air temperature
- Surface dew point depression
- Surface relative humidity
- Historical weather station observations
- Fuels Model
- Machine Learning model using WRF weather model output to approximate live fuel moisture.

Model outputs

The following are outputs of SCE's weather and fuels modeling:

- Air temperature
- Dew point temperature
- Dew point depression
- Mean Sea Level Pressure
- Relative humidity
- Wind velocity (speed, direction, and gust)
- Incoming shortwave radiation
- Geopotential Heights
- Omega (vertical velocity)
- Absolute Vorticity
- Dead Fuel Moisture
- Live Fuel Moisture

- Normalized Difference Vegetation Index
- Energy Release Component
- Burning Index
- Spread Component
- Ignition Component
- Keetch-Byram Index
- Growing Season Index
- Large Fire Potential Weather Component
- Large Fire Potential Fuel Moisture Component
- Greenness
- Convective Available Potential Energy
- Lifted Index
- Total Totals
- Rainfall
- Snow water equivalent
- Precipitable Water
- Peak 15 min rainfall accumulation
- Low, Mid, and High Cloud Cover
- Soil moisture
- Soil temperature
- Probability of exceeding sustained wind speed thresholds
- Probability of exceeding gust wind speed thresholds
- Probability of exceeding dew point depression bins
- Weather Score component of the Fire Potential Index
- Probability of exceeding Weather Score component of the Fire Potential Index
- Fire Potential Index

Separate modules (e.g., local weather analysis and local vegetation analysis)

The WRF model deployed by SCE for its in-house weather modeling system is composed of several separate modules that can be customized around forecast accuracy. These include the choice of initial and lateral boundary conditions, the underlying terrain resolution, and each of the physics parameterizations specified in Table SCE 10-01.

While each of these represent individual modules, they are linked within the WRF framework such that regardless of the module settings used to create a final forecast, a set of standard WRF output is created thereby providing flexibility in the form of allowing SCE to tailor module choice for improved forecast accuracy. This framework also allows SCE and its vendors to quickly test new module options as they become available from the research community. The initial and lateral boundary conditions provide information on both the synoptic and mesoscale weather features that will affect SCE's service territory, which are then downscaled within the WRF model to finer detail. Inclusive in the

WRF model solution is a module known as the planetary boundary layer scheme, which is responsible for including the impacts of large eddy scale weather on the overall weather solution as well as the land surface module responsible for including the impacts of local topography and land cover on the weather forecast.

Separate from SCE's numerical weather prediction system described above is SCE's machine learning forecast modules. The machine learning modules leverage the output from the numerical weather prediction systems as input and then remove forecast biases from these inputs based on historical weather observations co-located at the forecast points. The machine learning modules and the ensemble forecast output provide additional information on forecast uncertainty to SMEs. As of the end of 2024, machine learning has been deployed at 1,624 weather station locations throughout SCE's service territory in SCE's original machine learning build-out effort, which leverages the control model as input into the machine learning algorithm. Also in 2024, SCE implemented three new machine learning forecast systems at a total of 1,483 weather station locations leveraging the SCE ensemble forecasts as input, and one additional machine learning forecast system based on public weather model data at 1,947 weather stations within SCE's service territory.

SCE's fuel moisture modeling is a separate module that leverages SCE's weather forecast output in conjunction with mathematical algorithms to estimate dead fuel moisture across the service territory. In addition, SCE, through its vendor, Technosylva, has developed a machine learning model that has been trained on SCE's gridded historic weather and fuels data to predict live fuel moisture through the forecast period.

Finally, since SCE's last WMP submission, SCE has implemented hourly-updated nowcasts from both the HRRR and down-scaled HRRR using the US Forecast Service Wind Ninja diagnostic model. The nowcasts provide new forecasts of sustained wind speed and wind gust speed every hour out to a horizon of six hours. The nowcasts provide new data to meteorologists on short-term wind trends and were the result of a collaboration between SCE and UCSB.

Collectively, SCE's weather and fuels model output are linked to shapefiles of SCE's infrastructure to produce forecasts directly on assets.

Subject matter expert (SME) assessment of forecasts

SCE Weather Services assesses weather model forecast outputs distilled to circuit, circuit segment, transmission-line monitoring zones, and weather station locations from models produced in house (i.e., the ensemble and machine learning guidance described above) as well as publicly available from government weather agencies. Automation is used to quickly identify areas of concern meeting key weather and fuels thresholds for meteorologist and fire scientist assessment.

Use of multiple weather models and probabilistic forecast output allows SMEs to evaluate multiple possible forecast outcomes and their likelihood of occurrence. The machine learning models provide point forecasts that have been bias-corrected and probabilistically calibrated by historic observed weather that has occurred at that location. The team validates weather model forecasts for accuracy after each PSPS event and at the end of each year. SCE Weather Services additionally consults expert forecasts from the National Weather Service through publicly available weather discussions. Finally, SCE Weather Services uses historical climatological data compiled from each of our 1,780+ weather stations installed on our distribution, sub-transmission and transmission systems. This climatological data helps the forecaster to calibrate forecast expectations with true, observable outcomes that have been recorded.

SCE's Fire Sciences assesses fuel conditions by reviewing its in-house fuel moisture modeling output and comparing that to live fuel moisture sampling observations. This information combined with meteorological forecasts helps SCE provide a daily assessment of fire potential across the landscape.

SCE's meteorologists review weather forecasts at a minimum of once per day.

Spatial granularity of forecasts

All internal WRF models have a spatial granularity of either two-km or one-km. All internal WRF models are configured with 52 vertical levels. All machine learning models are generated at weather station points. Nowcasts from the US Forest Service Wind Ninja model are output on a 500-m grid length.

Time Horizon

The maximum time horizon of SCE's in-house weather forecast and machine learning capabilities is seven days. SCE meteorologists consult publicly available weather model guidance from vendors and the National Weather Service at longer forecast horizons up to two weeks in advance to gain knowledge on the broad-scale weather pattern and potential future changes.

Highlights Since Last WMP Submission

Since the last WMP filing, SCE has continued to improve its weather forecast system by focusing on increasing the use of machine learning algorithms to improve forecast accuracy. At the time of this filing, SCE has five machine-learning-based weather forecast systems that augment traditional weather forecast output for superior accuracy, especially under high wind regimes. Machine learning models have been developed for up to 1,624 weather station locations using internal weather model data and up to 1,947 weather station locations from public forecast data. The multiple machine learning systems allow SCE to plan for different forecast weather scenarios that sample uncertainties in the driving data (e.g., weather model initial condition source) and have built forecast continuity in SCE's machine learning approach.

Machine learning forecast corrections have been expanded beyond the sustained wind speed and gust speed predictions to include temperature and dew point depression variables that are important factors in the fire potential index score. Calibrated estimates of forecast uncertainty (e.g., probabilities of exceeding key thresholds) in these parameters are now provided at each weather station, allowing meteorologists better ability to plan around forecast scenarios and event likelihood. Existing machine learning models have been retrained each year to learn from recent weather events.

SCE has also implemented new technologies evaluated by academic research partner UCSB. UCSB evaluated rapidly updating short-term forecasts from the HRRR model and US Forest Service Wind Ninja model initialized from the HRRR. SCE implemented both forecast sources for nowcasting use, which aids meteorologists in understanding short-term wind trends. These "nowcasts" update once per hour and provide output for sustained wind speed and wind gust speed at resolutions down to 500-m grid spacing. SCE learned through the research partnership the strengths and limitations of both model systems.

UCSB also developed a deep learning model to translate irregularly spaced weather station observations into a regularly spaced grid with 500-m grid length, providing insight into the real-time weather conditions over locations that do not have weather station coverage. This model has been named the Deep Learning Gridding Meteorological Model (DLGNOME) by UCSB and has been implemented by SCE since the last WMP filing. SCE and UCSB have since expanded their research collaboration by looking at ways to leverage the DLGNOME and public forecasts as input to generate very-high-resolution forecasts (500-m grid spacing) at a fraction of the computational cost of traditional numerical weather prediction models. Research in this area continues and is following trends in the field of meteorology to increase use of artificial intelligence techniques to move beyond traditional weather model approaches.

SCE has additionally continued to update its gridded historical reanalysis dataset by twice-annual data refreshes.

10.5.2 Known Limitations of Existing Approach

The electrical corporation must describe any known limitations of its existing modeling approach resulting from assumptions, data availability, and computational resources. It must discuss the impact of these limitations on the modeling outputs.

SCE relies on numerical weather prediction models based on current state-of-the-art scientific methods developed and supported primarily by academia and government institutions. Several known limitations exist not only within SCE's weather models but generally all operational weather models in existence today. These limitations include:

1. It is not possible to achieve a perfect weather forecast because no perfect initial and boundary conditions exist to drive weather models. No perfect initial and boundary conditions exist because current observations sources used to determine the current state of the atmosphere do not provide complete planetary coverage (this includes areas well beyond the borders of the SCE territory). Additionally, such observation sources are subject to sampling errors that can result in inaccurate forecasts. SCE relies on the federal government to assimilate all surface and upper air observations into the initial and boundary conditions used as input into our WRF

models. The accuracy of the initial conditions is limited to the accuracy of the methods used in national meteorology centers like NCEP and the European Centre for Medium-range Weather Forecasts. SCE uses multiple initial and boundary conditions to account for these uncertainties in its ensemble modeling approach.

2. There are no known analytical solutions to the equations of motion describing the state of the atmosphere. In other words, the equations used to predict the future state of the weather contain unknown terms that are parameterized using empirical experimental data from field campaigns. Such parameterizations do not provide perfect fits and can result in forecast errors. SCE has tested available physics parameterizations to choose those that provide the best forecast accuracy over our territory. SCE uses multiple parameterization choices to sample these unknowns in its ensemble approach.
3. Current state-of-the-art weather models such as the WRF model are designed for grid lengths of roughly one km by one km and larger due to computational restraints and the physical parameterizations limitations mentioned in (2). This limits the granularity of weather models until higher computational power is available and new physics parameterizations can be developed for smaller scales. The result is that fine-scale, unresolvable meteorology features impacting observations may be missed by weather models.
4. Computational constraints limit the number of high-resolution weather models SCE can run in-house, as well as the feasible forecast horizon for weather models. Currently this limits SCE to a forecast horizon of seven days, which is adequate for short- to medium-range planning. Additionally, it limits the number of ensemble members SCE can run in house, as well as the forecast update frequency as spare cycles are not currently available to run many rapid updates per day.
5. Weather model outputs can contain systematic (repeatable) bias resulting in inaccurate forecasts. SCE is removing these biases by using machine learning to create bias-corrected forecasts. Such forecasts require observations to train the machine learning to detect patterns in forecast error based on prior forecast-observation pairs. Given the dependence on observations for training, statistically correct forecasts are only available at locations where observations exist and with a long enough record for machine learning training. Still such forecasts will be subject to errors described in (1) and no perfect machine learning forecast exists. To overcome this, SCE has developed, and will continue to expand, probabilistic machine learning forecasts for wind speed and gust that estimate the possible forecast in each updated forecast.
6. Short periods of record for forecast evaluation and machine learning. Weather stations are used to evaluate forecast performance and train SCE's machine learning models. However, development of machine learning models requires at least six months of historical observations data to train new models. Thus, the coverage of SCE's machine learning network is limited to only those locations with sufficient historical data to train new models. Additionally, as the period of record for observations increases, existing machine learning model accuracy will be improved through retraining over more weather events.

7. Machine learning forecasts are limited by the quality of the real-time input and training datasets. For example, if the driving forecast data fed into the machine learning forecast models is subject to large error (for example by a large uncertainty in the timing or placement of a meteorological feature some period in the future), the machine learning models may propagate these errors forward into the predicted solutions.
8. Machine learning forecasts are also created individually for each weather station location and for each variable, meaning they are not physically linked. In some cases, this can result in unphysical forecasts that need to be vetted by meteorologists for accuracy.
9. Because modeling fuel moisture is dependent on parameters such as temperature, atmospheric moisture, soil moisture, and evaporation rates, it is affected by the same limitations that are common in the numerical modeling stated above which includes biases and other forecast errors. In addition, uncertainties within the physical processes of vegetation phenology compound the errors associated with vegetation moisture outputs.

10.5.3 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*
- *Increase in related frequency*

In the 2023 to 2025 WMP cycle, SCE focused on developing new forecast and monitoring capabilities through work with vendors and academia, making significant strides in situational awareness maturity. SCE developed new machine learning forecast systems, continued to refresh its gridded historical dataset and wind climatology, developed new visualization tools, and evaluated and implemented new and emerging technologies developed through academic research.

In the 2026 to 2028 WMP cycle, SCE will focus on maintaining and refining existing capabilities for improved accuracy, as well as continuing to evaluate new and emerging technologies for potential implementation. SCE plans to:

- Expand its machine learning forecast network to any newly added weather station locations with enough historical data for model training
- Retrain its existing machine learning forecast systems to increase forecast accuracy as the historical observations record grows and new events are sampled

- Evaluate and implement successful refinements to its numerical weather prediction models and/or machine learning forecast techniques
- Continue to work with academia to build out and possibly implement new forecast technologies that follow the current trends in the state of the science of weather prediction. At the time of the WMP filing, SCE is working with UCSB to develop a new way to generate high resolution weather forecasts from coarse public weather model forecast data using new artificial intelligence techniques instead of computationally expensive numerical weather prediction models
- Continue to extend its historical dataset to maintain currency
- Maintain its subscription data feed of the European weather model
- Maintain weather visualization and circuit geometry update capabilities
- Deploy a state-of-the-art forecasting system leveraging vendor-hosted and supported cloud High-Performance Computing Clusters (HPCCs). HPCCs will better facilitate the aggregation of advanced algorithms for modeling and simulation, such as machine learning and data assimilation, which require substantial computational power. Accurate predictions often necessitate high-resolution data, which involves processing vast amounts of information over smaller spatial and temporal scales. The upgrade will enhance forecast modeling and analytics, extend the forecasting horizon from four to seven days, and reduce the time required for data file transfers. This system supports ensemble forecasting, where multiple simulations are run with varied initial conditions, aiding in understanding wildfire weather uncertainty, and improving forecasting reliability quickly. This system's ability to forecast through the duration of a multi-day event will improve SCE's ability to forecast circuits likely to reach PSPS criteria through the duration of the event. These tools increase SCE's capacity to better forecast elevated weather conditions and potential wildfire activity, which in turn leads to better decision-making information during regular operations and emergencies and are used by SCE fire management officers as well. Data from these tools also enhances situational awareness by providing real-time information. This will improve SCE's ability to provide customers and public agencies PSPS notifications that meet CPUC-mandated timeframes.
- Downscale the Climate Forecast System (CFS) which helps to model the interplay between the oceans and the atmosphere on a global scale, to tease out details that could provide more insights into projections of temperature, precipitation, and wind out to three weeks. These downscaled forecasts are anticipated to improve Fire Sciences' extended forecasts and seasonal outlooks by having these products be more data driven. Models are retrained every two to four years in order to better account for any large-scale atmospheric changes.[183]

183 In meteorology, large-scale is defined as a horizontal length scale on the order of 1000 kilometers (about 620 miles) or more.

10.5.4 Evaluating Activities

The electrical corporation must describe its procedures for the ongoing evaluation of the efficacy of its weather forecasting activity (program).

To measure the efficacy of SCE's weather forecast mitigations, SCE creates annual weather forecast verification summaries by comparing forecast weather conditions to available observations. The verifications indicate overall forecast performance, which is used to further understand the limitations of current forecast capabilities. Additionally, SCE monitors its weather forecasting program through post-event analyses for PSPS events. Finally, SCE asks vendors to include verification of developmental forecast systems within statements of work prior to implementation. These summaries inform future continuous improvement efforts around weather forecasting as well as help to gain understanding of known modeling limitations.

10.5.5 Weather Station Maintenance and Calibration

In this section, the electrical corporation must provide a narrative describing maintenance and calibration and risk impacts due to weather station inoperability. The narrative should be no more than one page and include the following:

- *Acceptable percentage of weather station outages as defined by the electric corporation*
- *Justification for how reduced coverage does/does not impact risk to PSPS decision making and any methods to reduce those impacts*
- *Any limitations to conducting annual maintenance and calibrations (such as staffing, training, terrain, access, etc.)*
    - *This must include the number of incomplete maintenance or calibration events for weather stations in the last calendar year*
- *A description of what efforts are in place to ensure acceptable levels of weather station coverage throughout the electric corporation's service territory*

As of January 1, 2025, SCE operates and maintains a network of 1,787 weather stations. SCE strives to maintain 99% network operability, when not experiencing externally induced events (e.g., snowstorms, fire damage, network failures, etc.). Maintenance includes an annual calibration to validate that data observed by sensors in the field aligns with values of those being collected by a calibrated sensor. The various weather station instruments are cleaned, tightened, re-aligned, replaced, and otherwise maintained as needed during the calibration. Adjustments are made to maintain sensor accuracy and routine replacement of aging sensors or parts are completed as necessary.

SCE does not feel there is reduced coverage of weather stations in its HFRA, where these stations are used for PSPS decision-making.

Weather Station maintenance on a network of 1,780+ weather stations can face challenges such as access due to road conditions, inclement weather, additional work schedules, or access due to land ownership permissions. In 2024, annual maintenance on the weather station network was performed on all stations except two. Station SCE-3210 is in a remote location only accessible via mule pack or a hydroelectric trolley, and the trolley was out of service. Station SCE-3709 was damaged during a car hit pole incident and a replacement station was ordered. SCE-3709 was re-installed and calibrated on January 8, 2025 and SCE-3210 will be visited and calibrated at the next available opportunity.

Starting in 2025, maintenance and calibration activities will be able to be reported in SCE's Quarterly Data Report (QDR) process. SCE typically assigns a weather station to a distribution circuit or circuit segment that traverses HFRA where the weather station falls within a half mile of the overhead portion of the distribution circuit. Sub-transmission and transmission lines are customarily assigned weather stations that are within one mile of the line. Where needed, SCE may go beyond the half / one mile to ensure a segment mapping exists in areas where station density is lower. SCE also maps RAWS, ASOS and other higher quality publicly available weather stations to circuits if they well represent weather conditions along the circuit or line. SCE continually evaluates and validates coverage of weather stations through PSPS events.

The assigned stations provide weather data that is representative of the localized area and ensures coverage of customers on circuits throughout SCE's HFRA. While SCE SMEs generally consider that weather station saturation is sufficient to monitor conditions in circuits in HFRA areas, PSPS operations or weather services may occasionally recommend a new weather station installation in an area that could result in decreased customer impacts from PSPS or better weather sampling in that localized area.

SCE's weather station calibration activity targets are provided in Table 10-1. If factors outside of SCE's control facilitate execution of additional units, SCE will strive to complete 1,750 calibrations annually in SCE's HFRA. This level of execution depends on exogenous factors like access issues due to land owner refusals or inclement weather.

10.6 Fire Potential Index

The electrical corporation must describe its process for calculating its fire potential index (FPI) or a similar a landscape-scale index used as a proxy for assessing real-time risk of a wildfire under current and forecasted weather conditions.[92] The electrical corporation's description must include the following:

- *Its existing calculation approach and how its FPI is used in its operations*
- *The known limitations of its existing approach*
- *Implementation schedule for any planned changes to the system*

The electrical corporation must reference the Tracking ID where appropriate

10.6.1 Existing Calculation Approach and Use

The electrical corporation must describe:

- *How it calculated its own FPI or if uses an external source, such as the United States Geological Survey*
- *Assumptions in calculations and justification for each assumption*
- *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 10-5 provides a template for the required information.

SCE assesses daily wildfire potential through use of its Fire Potential Index (FPI), which is based on weather and fuel (vegetation) conditions. FPI is calculated at the circuit level twice daily with output every three hours, out to seven days and includes the following inputs:

- Wind speed—Sustained wind velocity at six meters above ground level.
- Dew point depression—The dryness of the air as represented by the difference between air temperature and dew point temperature at two meters above ground level.
- Energy release component (ERC)—As defined by the U.S. Department of Agriculture: “The available energy in British Thermal Unit (BTU) per unit area (square foot) within the flaming front at the head of a fire ... reflects the contribution of all live and dead fuels to potential fire intensity.”[184]
- 10-hour dead fuel moisture—A measure of the amount of moisture in ¼-inch diameter dead fuels, such as small twigs and sticks.
- 100-hour dead fuel moisture—A measure of the amount of moisture in 1- to 3-inch diameter dead fuels, i.e., dead, woody material such as small branches.
- Live fuel moisture—A measure of the amount of moisture in living vegetation.
- Normalized Difference Vegetation Index (NDVI)— As defined by the U.S. Department of the Interior: “... used to quantify vegetation greenness and is useful in understanding vegetation density and assessing changes in plant health.”[185]

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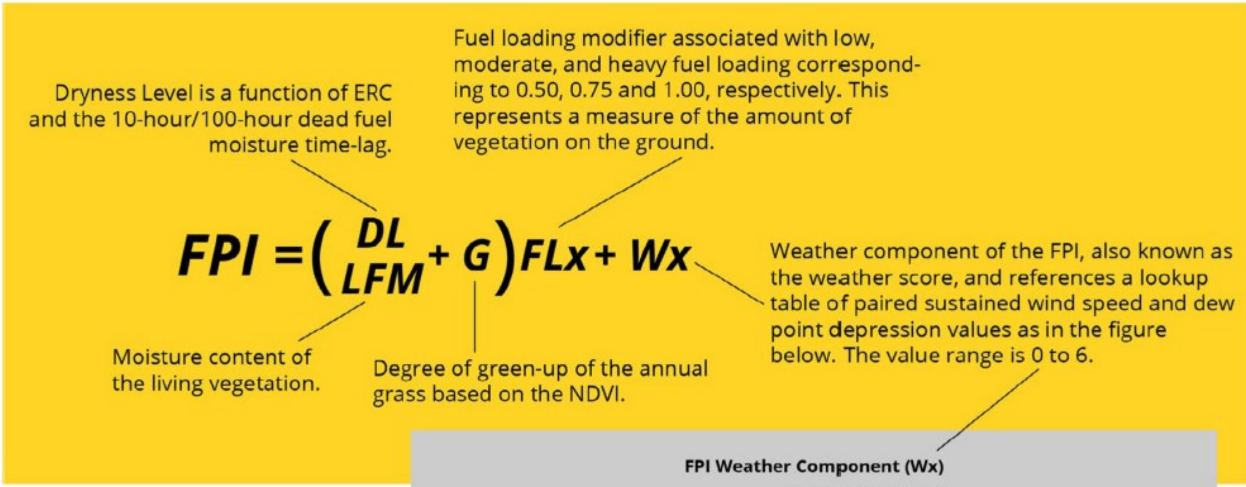
184 U.S. Department of Agriculture. n.d. “Energy Release Component (ERC) Fact Sheet.” Forest Service. Accessed April 14, 2021. https://www.fs.usda.gov/Internet/FSE_Documents/stelprdb5339121.pdf.

185 Department of the Interior. n.d. Landsat Normalized Difference Vegetation Index. Access April 14, 2021. https://www.usgs.gov/core-science-systems/nli/landsat/landsat-normalized-difference-vegetation-index?qt-science_support_page_related_con=0#qt-science_support_page_related_com.

Figure SCE 10-05: Fire Potential Index Equation



FPI Weather Component (Wx)

Dew Point Depression	Wind Speed (mph) <=5	6-10	11-16	17-22	23-28	>=29
>=50	2	3	3	4	5	6
40-49	2	2	3	3	4	5
30-39	1	2	2	3	3	4
20-29	1	1	2	2	3	3
10-19	0	0	1	1	1	1
<10	0	0	0	0	0	0

Based on a risk analysis of the historical fire data, the FPI portion of a circuit's PSPS threshold is set at 13 for most areas. However, exceptions exist for certain areas and situations in which the FPI threshold is set at 12. These include:

- FCZ1 (Coastal region) — The threshold for FCZ1 remains at 12 because calculated historical probabilities indicate a significantly higher ignition risk factor at an FPI threshold of 13 for this FCZ than for the other FCZs (2, 3, 4, 9, and 10)
- Geographic Area Coordination Center (GACC) preparedness level of 4 or 5 — The GACC coordinates multiple federal and state agencies to track and manage regional fire resources. It provides a daily fire preparedness level on a score of 1 to 5. A high score signals that there could be resource issues in responding to a fire
- Circuits located in an active Fire Science AOC — AOCs are areas within FCZs that are at high risk for fire with significant community impact. This designation is based on factors that are common to FPI as well as egress, fire history, and fire consequence

How it uses its or an FPI in its operations

SCE uses the FPI to estimate fire potential across the landscape based on weather and fuel (vegetation) conditions and is one data point used in the PSPS decision-making process.

Table 10-5: Fire Potential Features

Feature Group	Feature	Altitude	Description	Source	Update Cadence	Spatial Granularity	Temporal Granularity
Weather Component	Wind Speed	Surface	Wind speed in miles per hour at 6 meters above ground	Deterministic Weather model	2x per day	1 km and 2 km	3 Hour Forecasts at a maximum of 7 days
Weather Component	Dewpoint Depression	Surface	The difference between the temperature and dew point temperature in degrees Fahrenheit at 2 meters above ground	Deterministic Weather model	2x per day	1 km and 2 km	3 Hour Forecasts at a maximum of 7 days
Fuels Component	Dryness Level	Surface	Comprised of the ERC and the 10-hour/100-hour dead fuel moisture time-lag[186]	Deterministic Weather model	2x per day	2 km	3 Hour Forecasts for 7 days
Fuels Component	Live Fuel Moisture	Surface	Moisture content of the living vegetation in percent.	Deterministic Weather model	2x per day	2 km	3 Hour Forecasts for 7 days
Fuels Component	Grass Green-Up	Surface	The degree of green-up of the annual grass based on the Normalized Difference Vegetation Index (NDVI)	Deterministic Weather model	2x per day	2 km	3 Hour Forecasts for 7 days

186 The time required for dead vegetation (1/2” diameter) to respond to changes in ambient temperature and humidity.

10.6.2 Known Limitations of Existing Approach

The electrical corporation must describe any known limitations of current FPI calculation. Specifically, list of any changes implemented since its last WMP submission, including justification of changes and lessons learned, where applicable.

The current FPI is based on SDG&E's index, which was adopted at SCE in 2018 and used for PSPS beginning in 2019. In 2019, SCE added a fuel-loading modifier to account for areas where fuels are sparse and unlikely to support a significant fire.

In 2021, SCE calibrated the index and was able to raise FPI thresholds across much of its HFRA as a result. While FPI is a good metric for identifying critical weather events that can result in high fire potential and PSPS, SCE refined its FPI over time. In 2021, SCE developed a new fire potential index (FPI 2.0) that employs a more sophisticated methodology for addressing the diversity of fuel conditions across the service territory. It also puts more emphasis on wind speed as wind can dominate the fire environment. This refined index will better capture the sensitivity of critical fire weather conditions as well as highlight extreme events. The components of FPI 2.0 have been leveraged to develop the Fire Behavior Matrix (FBM), which plots the weather and fuels components independently on a horizontal and vertical axis. The advantage of deconstructing FPI 2.0 in this way allows for a better visual understanding of which components are contributing most to the overall fire potential.

10.6.3 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.

SCE will continue to use FPI 2.0 and the FBM in operational decisions and mitigation efforts moving forward. FBM was used for fire weather day selection for FireSight 8 (please refer to Sec. 5.2 for more information). Its direct usage in PSPS decision-making is still under consideration.

11 EMERGENCY PREPAREDNESS, COLLABORATION, AND COMMUNITY OUTREACH

Each electrical corporation must develop and adopt an emergency preparedness plan in compliance with the standards established by the CPUC pursuant to Public Utilities Code section 768.6(a).

11.1 Targets

In this section, each electrical corporation must provide qualitative targets for emergency preparedness, collaboration, and community outreach.

The electrical corporation must provide at least one qualitative target for the following initiatives:

- *Emergency Preparedness and Recovery Plan (Section 11.2)*
- *External Collaboration and Coordination (Section 11.3)*
- *Public Communication, Outreach, and Education (Section 11.4)*
- *Customer Support in Wildfire and PSPS Emergencies (Section 11.5)*

11.1.1 Qualitative Targets

The electrical corporation must provide qualitative targets for its three-year plan for implementing and improving its emergency preparedness, collaboration, and community outreach, including the following:

- *Identification of which initiative(s) and activity/activities in the WMP the electrical corporation is implementing to achieve the stated target, including Tracking IDs and the Tracking ID(s) used in past WMPs ("Previous Tracking ID"), if applicable*
- *A completion date for when the electrical corporation will achieve the target*
- *Reference(s) to the WMP section(s) or appendix, including page numbers, where the details of the target(s) are documented and substantiated*

This information must be provided in Table 11-1 for the three-year cycle. Examples of the required format and minimum acceptable level of information are provided below.

See Table 11-1 for the qualitative targets for SCE's three-year plan for implementing and improving our emergency preparedness, collaboration, and community outreach.

Table 11-1: Emergency Preparedness and Tribal/Stakeholder Outreach Targets by Year[187]

Initiative	*Activity (Tracking ID #)*	*Previous Tracking ID, if applicable*	*2026 End of Year Total/Completion Date*	*2027 Status*	*2028 Status*	*Section; Page number*
11.2 Emergency Preparedness and Recovery Plan	SCE Emergency Response Training (DEP-2)	DEP-2	PSPS response teams are fully qualified/requalified by 7/1 annually to maintain readiness	PSPS response teams are fully qualified/requalified by 7/1 annually to maintain readiness	PSPS response teams are fully qualified/requalified by 7/1 annually to maintain readiness	11.2; p. 435
11.3 External Collaboration and Coordination	Aerial Suppression (DEP-5)	DEP-5	SCE will continue to reassess availability and funding for aerial suppression resources in SCE's service territory annually to determine ongoing QRF strategy	SCE will continue to reassess availability and funding for aerial suppression resources in SCE's service territory annually to determine ongoing QRF strategy	SCE will continue to reassess availability and funding for aerial suppression resources in SCE's service territory annually to determine ongoing QRF strategy	11.3; p. 445
11.4 Public Communication, Outreach, and Education Awareness	Wildfire Safety Community Meetings (DEP-1)	DEP-1	SCE will host at least two virtual wildfire community safety meetings (additional meetings will be hosted based on PSPS activity and/or community needs)	SCE will host at least two virtual wildfire community safety meetings (additional meetings will be hosted based on PSPS activity and/or community needs)	SCE will host at least two virtual wildfire community safety meetings (additional meetings will be hosted based on PSPS activity and/or community needs)	11.4; p. 456
11.4 Public Communication, Outreach, and Education Awareness	Customer Research and Education (DEP-4)	DEP-4	SCE will conduct at least three wildfire mitigation / PSPS-related customer studies (additional surveys will be conducted based on PSPS activity and/or community needs)	SCE will conduct at least three wildfire mitigation / PSPS-related customer studies (additional surveys will be conducted based on PSPS activity and/or community needs)	SCE will conduct at least three wildfire mitigation / PSPS-related customer studies (additional surveys will be conducted based on PSPS activity and/or community needs)	11.4; p. 456

187 The completion date for all qualitative targets is December 31st unless otherwise specified.

Initiative	*Activity (Tracking ID #)*	*Previous Tracking ID, if applicable*	*2026 End of Year Total/Completion Date*	*2027 Status*	*2028 Status*	*Section; Page number*
11.5 Customer Support in Wildfire and PSPS Emergencies	Customer Care Programs: Critical Care Backup Battery Program (PSPS-2)	PSPS-2	Complete 85% of battery deliveries to eligible customers within 30 business days of program enrollment* *Subject to customer responsiveness, availability, reschedule requests, and battery supply constraints	Complete 85% of battery deliveries to eligible customers within 30 business days of program enrollment* *Subject to customer responsiveness, availability, reschedule requests, and battery supply constraints	Complete 85% of battery deliveries to eligible customers within 30 business days of program enrollment* *Subject to customer responsiveness, availability, reschedule requests, and battery supply constraints	11.5; p. 472
11.5 Customer Support in Wildfire and PSPS Emergencies	Customer Care Programs: Portable Power Station and Generator Rebates (PSPS-3)	PSPS-3	Process 85% of all rebate claims within 30 business days* of receipt from website vendor *Excluding website related delays and subject to receiving all required customer information	Process 85% of all rebate claims within 30 business days* of receipt from website vendor *Excluding website related delays and subject to receiving all required customer information	Process 85% of all rebate claims within 30 business days* of receipt from website vendor *Excluding website related delays and subject to receiving all required customer information	11.5; p. 472

11.2 Emergency Preparedness and Recovery Plan

In this section, the electrical corporation must provide an overview of how it has evaluated, developed, and integrated wildfire- and PSPS-specific emergency preparedness strategies, practices, policies, and procedures into its overall emergency plan based on the minimum standards described in GO 166. The electrical corporation must provide the title of and link to its latest emergency preparedness report, the date of the report, and an indication of whether the plan complies with CPUC 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*

The electrical corporation must reference the Tracking ID where *appropriate.*

SCE's All-Hazards Plan (AHP) (Version 4, December 2024) outlines SCE's approach to emergency management, which includes wildfires and outages related to wildfires. The AHP serves as the base document for strategic, operational, and tactical planning for emergencies and highlights the roles and responsibilities of each organizational unit in SCE during an incident response. While incident types vary greatly, the response activities are similar and handled through an All-Hazards Approach. The AHP focuses on capabilities critical to address a full spectrum of disruptive events, including natural and human-caused emergencies. The AHP is a whole company approach to continue operations and meet the diverse needs of the whole community in coordination and participation with SCE's emergency response partners. SCE has also developed hazard-specific annexes as part of the AHP to focus on special planning needs required for that specific threat/hazard. One of the hazard-specific annexes, the PSPS Protocol, outlines the process to mitigate, plan for, respond to, and recover from a PSPS event that is activated in response to elevated or extreme fire weather in designated High Fire Risk Areas (HFRAs) and focuses on PSPS-specific aspects of emergency management. The PSPS protocol describes the procedures and systems used by SCE and the roles and responsibilities of the PSPS Incident Management Team (IMT) when managing a PSPS event. This protocol describes PSPS decision-making, cadence of operations, and notifications to customers and stakeholders including public safety partners and operational agencies.

As noted on pages 23-24 of the AHP, the plan is informed by requirements from several sources, including General Order (GO) 166. In addition, in 2023, SCE performed a comprehensive update to the AHP that included additional elements required by CPUC Decision (D.)21-05-019, which was issued in Rulemaking (R.)15-06-009. The AHP has an annual review process to include updates resulting from feedback from external and internal stakeholders and guidance from regulatory agencies, and technical updates in accordance with the GO 166 program guidelines. The plan is finalized in December prior to the year for which it takes effect.

Another relevant SCE document that governs SCE's wildfire and PSPS emergency preparedness planning for response and recovery efforts is SCE System Operating Bulletin (SOB 322): Operation of Circuits Transversing High Fire Risk Areas, dated February 25, 2025.

11.2.1 Overview of Wildfire and PSPS Emergency Preparedness and Service Restoration

In this section, the electrical corporation must provide an overview of its wildfire- and PSPS-specific emergency preparedness and service restoration plan. The overview must describe the following:

- *Overview of protocols, policies, and procedures for responding to and recovering from a wildfire or PSPS event (e.g., means and methods for assessing conditions, decision- making framework, prioritizations). This must include:*
    - *An operational flow diagram illustrating key components of its wildfire- and PSPS-specific emergency response procedures from the moment of activation to response, recovery, and restoration of service*
    - *Separate overviews and operational flow diagrams for wildfires and PSPS events*
- *Key personnel, qualifications, and training that show the electrical corporation has trained the workforce to promptly restore service after wildfire or PSPS event, accounting for workers pursuant to mutual aid agreement or contracts. This must include:*
    - *The key roles and responsibilities, personnel resource planning (internal and external staffing needs), personnel qualifications, and required training programs*
    - *A brief narrative describing its process for planning to meet its internal and external staffing needs for emergency preparedness planning, preparedness, response, and recovery related to wildfire and PSPS*
    - *The name of each training program, a brief narrative of the purpose and scope of each training program, the frequency of each training program, and how the electrical corporation tracks who has completed the training program.*
- *Each Memorandum of Agreement (MOA) the electrical corporation has with state, city, county, and tribal agencies within its service territory on wildfire and/or PSPS emergency preparedness, response, and recovery activities. The electrical corporation must provide a brief summary of the MOA, including the agreed role(s) and responsibilities of the external agency before, during, and after a wildfire or PSPS emergency*
    - *Coordination and collaboration with public safety partners (e.g., emergency planning, interoperable communications)*
    - *Notification of and communication to customers before, during and after a wildfire or PSPS event*
    - *Improvements/updates made since the last Base WMP submission*

The overview must be no more than six pages. The electrical corporation may refer to its emergency preparedness plan to provide more detail. Where the electrical corporation has already reported the requested information in another section of the WMP, it must provide a cross-reference with a hyperlink to that section.

In addition, the electrical corporation must provide a table with a list of current gaps and limitations in evaluating, developing, and integrating wildfire- and PSPS-specific preparedness and planning features into its overall emergency preparedness and recovery plan(s). Where gaps or limitations exist, the electrical corporation must provide a remedial action plan and the timeline for resolving the gaps or limitations. Table 11-2 provides the required format and an example of the minimum level of content and detail required.

11.2.1.1 Overview of Protocols, Policies, and Procedures

SCE uses a phased approach for managing preparation for and response to wildfires, PSPS events, and other emergencies. There are three phases: (1) Pre-Incident, or activities prior to an incident, including a transition from normal operations to actions SCE takes when there is an increased likelihood of an emergency and actions we take when there is a credible threat of an emergency occurring; (2) Response, or activities SCE executes once an incident occurs; from activation of an IMT through the initial response and the sustained response;[188] and (3) Recovery, or activities that follow the completion of the incident, with a focus on long-term recovery. The table below shows the phases and sub-phases of SCE's Emergency Management Protocol.

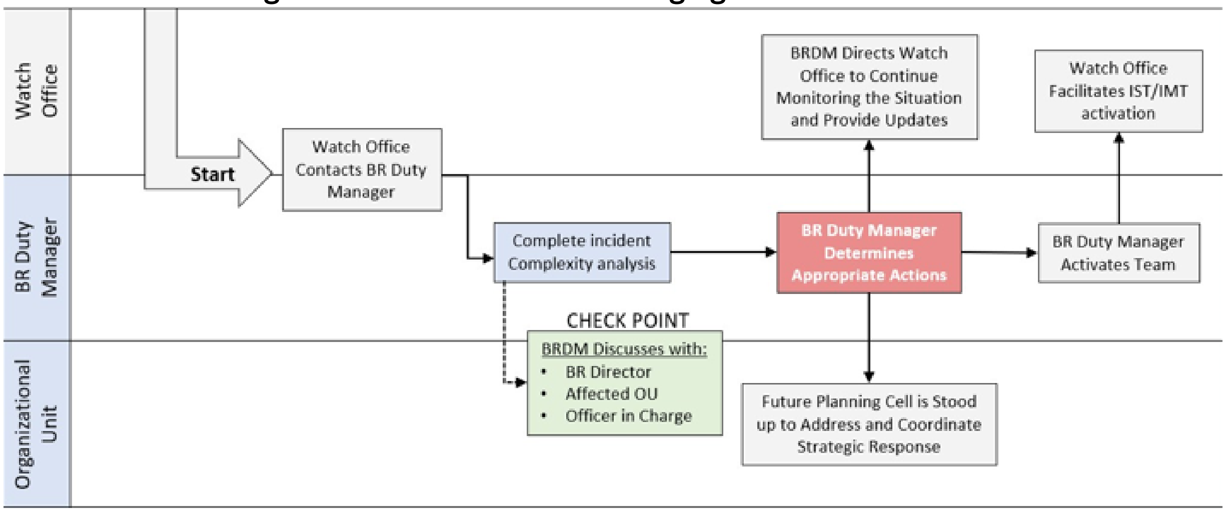
Table SCE 11-01: SCE's Emergency Management Phases

Pre-Incident			Response			Recovery
1A	1B	1C	2A	2B	2C	3A
Normal Operations	Increased Likelihood	Credible Threat	Activation	Initial Response	Sustained Response	Long-Term Recovery

During the Pre-Incident Phase, the transition from Normal Operations to an Increased Likelihood state will generally be triggered by situational awareness information from various sources, which may include SCE's operations centers, government or regulatory agencies, media, or first-hand observations. At this point, SCE's Watch Office begins monitoring the situation. The figure below shows the process for how SCE monitors an emerging situation and determines whether to activate an incident team.

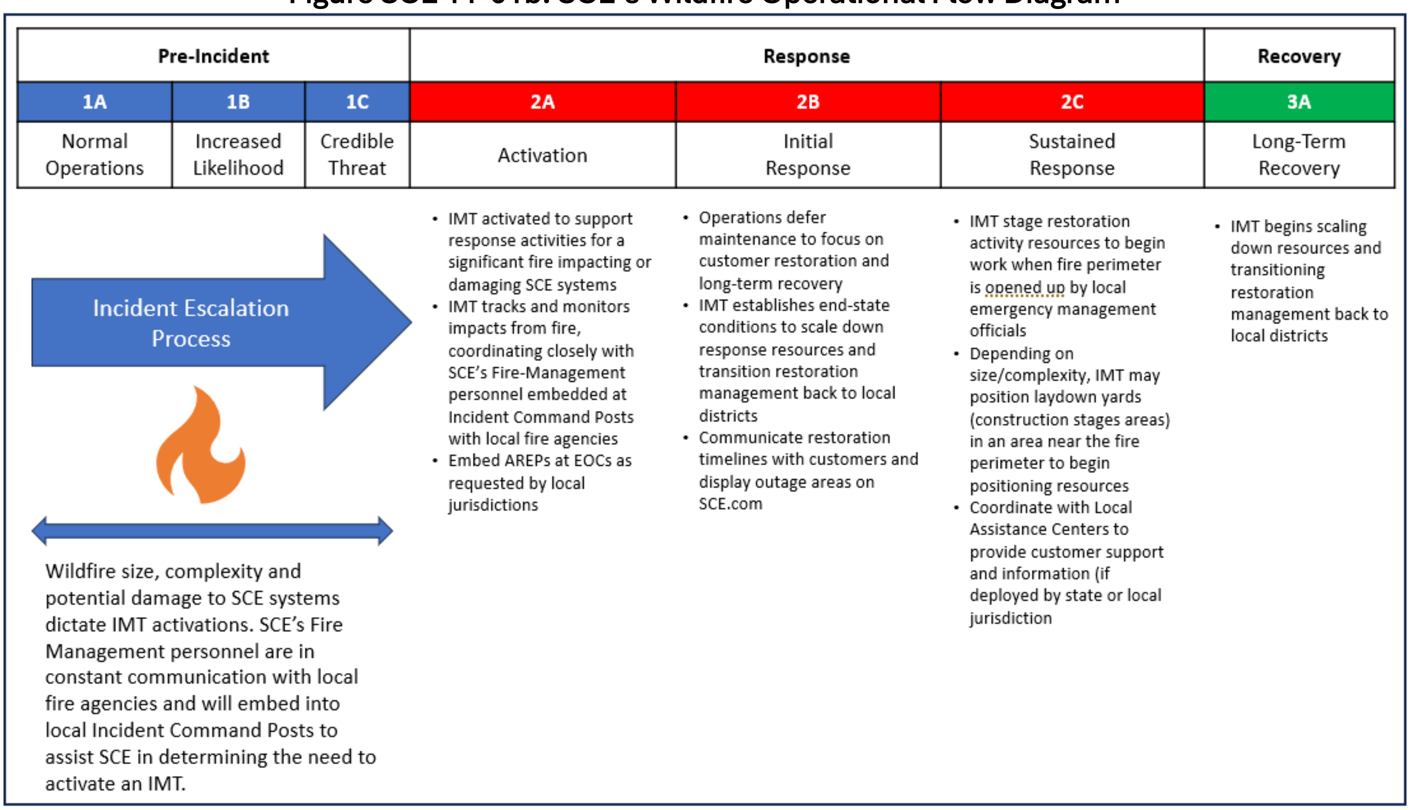
188 In some cases, SCE will stand up an Incident Support Team (IST). ISTs are more advanced teams, whose members go through additional training and are typically in a management role in the company. ISTs are also subject to IMT guidelines.

Figure SCE 11-01a: SCE's Emerging Situation Process



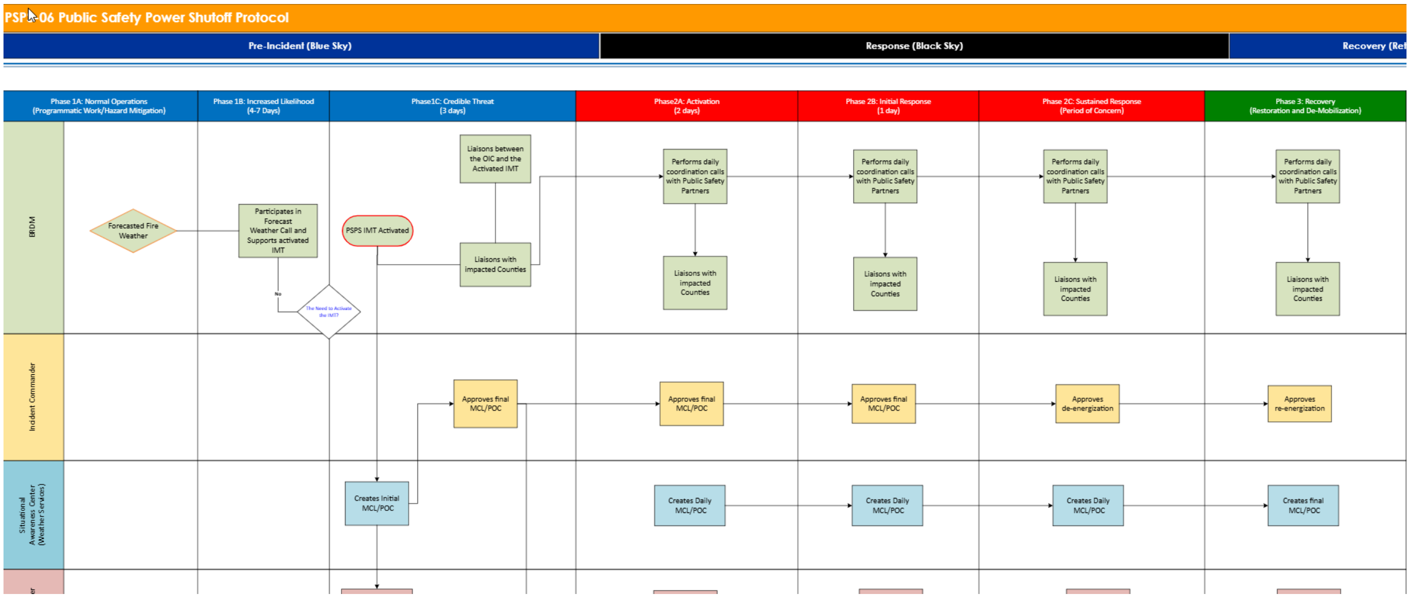
SCE's emergency management protocols, policies, and procedures can be applied to all types of emergencies. The figure below shows the operational flow diagram of activities SCE performs in each phase of emergency management for a wildfire incident.

Figure SCE 11-01b: SCE's Wildfire Operational Flow Diagram



The figure below shows a portion of the operational flow diagram of activities SCE performs in each phase of emergency management for a PSPS incident. The entire flow diagram is too large to include on a page and is therefore included in Appendix F: Supplemental Information.

Figure SCE 11-01c: SCE's PSPS Operational Flow Diagram



11.2.1.2 Key Personnel, Qualifications, and Training

11.2.1.2.1 Key Personnel Roles and Responsibilities

Key Personnel Roles & Responsibilities for Wildfire Incidents (also applies to all hazards)

- **Incident Commander (IC)**: Responsible for overall management and authority of Emergency Operations Center (EOC) operations, staff, the incident, and leads the Command & General Staff.
- **Safety Officer**: Monitors safety conditions and develops measures for ensuring the safety of all personnel.
- **Public Information Officer (PIO) and Incident Communications Team**: Develops messages and serves as the conduit for information to internal and external stakeholders, including the media. The PIO has overall responsibility for all communications.
- **Liaison Notification Officer (LNO)**: Serves as the primary contact for outside agencies and organizations as well as internal organizations not assigned to the incident.
- **Operations Section Chief (OSC)**: Conducts operations to accomplish the incident objectives. The OSC establishes tactics and directs all operational resources, as well as coordinates damage assessment activities and informs restoration prioritization across the company.
- **Planning Section Chief (PSC)**: Supports the incident action planning process by tracking resources, collecting/analyzing information, and maintaining documentation.

Key Personnel Roles & Responsibilities for PSPS Incidents

- **PSPS IC**: Directs mitigation strategies for potential public safety concerns and at-risk customers. The PSPS IC works with IMT to determine staffing and equipment requirements and approves the monitored circuit list, as well as approves circuits for de-energization and re-energization.
- **PSPS OSC**: Responsible for providing situational awareness, for both the incident and restoration decisions, to IMT Incident Commander, and supervising all operational actions, air operations and customer care functions.
- **PSPS Task Force** (Substation Tech Spec, GCC Liaison, PSPS Analyst, Transmission Tech Spec, Distribution Tech Spec, Customer Notifications Group, Operations Compliance Tech Spec):

Recommends de-energization and re-energization decisions and manages field resources, notifications, and circuit situational awareness.

- **Customer Care Branch (Customer Care Branch Director, Access and Functional Needs (AFN) Group, Customer Outreach)**: Responsible for customer programs including customer care resources, secondary notifications for medical baseline and critical care customers and the needs of the AFN community.
- **Planning Section Chief**: Coordinates across the IMT to establish incident response tempo, manage staffing and meeting cadence and provide required periodic reports to CalOES and CPUC.

11.2.1.2.2 Personnel Resource Planning

Figure SCE 11-01c above shows the process by which the Business Resiliency Duty Manager (BRDM) monitors an emerging situation and determines whether to activate an IMT or IST. The BRDM analyzes information and uses the incident complexity analysis to help inform decisions whether to activate an IMT. The IC and BRDM regularly evaluate the criteria in the incident complexity analysis throughout an activation to assess appropriate staffing levels.

Typically, at the start of an incident, Command and General staff will activate. Once the needs are better understood, the BRDM working with the IC can start to scale back resources to "Alert Status" if appropriate.[189] The Watch Office will identify which team members should respond immediately, which team members should be alerted to respond later to relieve the first team, and any deputy and assistant positions that should be staffed using the IMT weekly duty rotation calendar. This enables a more gradual and methodical approach to both escalation and de-escalation of resources and ultimately demobilization of an IMT.

For restoration, SCE may employ different strategies depending on the size, scope, complexity, and intensity of each incident. In smaller, more isolated incidents, SCE typically employs the standard order-based strategy that it uses under routine outage circumstances. This strategy is not effective in larger incidents where there is an overwhelming volume of orders. When incidents are larger, SCE moves to an area-based strategy where repair priorities are assigned by areas and circuits. The two strategy types, order- and area-based can be used together within an event as needed. For PSPS, IMT personnel monitor all circuits that are de-energized and will watch for winds to decrease below thresholds. Upon receiving the All- Clear declaration and approval from the PSPS IC, SCE personnel begin patrols and re-energization of circuits or circuit segments under PSPS de-energization. These patrols are intended to ensure there is no damage to SCE facilities before power can be safely restored.

11.2.1.2.3 Personnel Qualifications and Emergency Response Training (DEP-2)

SCE maintains a robust and highly skilled workforce (both employees and contractors) to provide effective emergency response and restore service during and after a major event. IMT and IST teams include qualified personnel from across the company whose emergency management roles use complementary skills and capabilities to those used in their day-to-day roles. For example, the Finance Section chief could be filled by someone in SCE's Financial organization. These team members acquire and master proficiency at emergency response through independent and instructor-led classes, exercises, and feedback. Small teams of trained individuals are qualified for leadership roles. Support roles have deeper rosters, and these "pooled" team members are on call one week out of every four or six weeks.

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189 Staff on "Alert Status" are on call and may be activated throughout the incident as needed.

Team members are required to take on-line training through FEMA's Emergency Management Institute (EMI) & California Specialized Training Institute (CSTI). These independent study courses provide a fundamental understanding of emergency management principles and concepts. SCE requires the following Independent Study (IS) courses as prerequisites to classroom training:

- FEMA IS 100.c – Introduction to Incident Command System (ICS)
- FEMA IS 200.c – ICS for Single Resources & Initial Action
- FEMA IS 700.b – National Incident Management
- FEMA IS 800.d – National Response Framework, an Introduction

After completing the pre-requisite courses, team members are required to take ICS 300 - Intermediate ICS for Expanding Incidents, and select team members may be required to take ICS 400 – Advanced Incident Command System for Complex Incidents. CSTI-certified instructors conduct the classroom training required for IST and IMT qualification. Course materials, which meet national Incident Management standards, include materials pertinent to the electric utility industry as well as training for situations unique to SCE.

Once training is complete, team members demonstrate proficiency in their position under the direct supervision of a qualified team member during a functional exercise or real-world activation. Collectively, self-study online and ICS classroom training, plus exercise/activation components are the minimum qualification requirements. Additional familiarity and skill development take place through formal and informal training throughout the year.

Each year SCE requires that all IMT, IST, and pooled positions go through requalification to maintain familiarity with their position and build on their knowledge, skills, and abilities. SCE reviews qualification requirements annually and communicates any changes to all IMT/IST members. To maintain qualification, a member must complete Position-Specific User Group Training and IMT/IST Requalification Training. SCE conducts two PSPS simulation exercises, one a table-top (walk through) exercise and the other a functional exercise, including role-playing. SCE also provides specialized training on an annual basis for PSPS IMT members who oversee and execute de-energization and restoration protocols.

11.2.1.2.4 Required Training Programs

SCE requires the following emergency preparedness and service restoration training programs to prepare personnel to handle emergency situations:

- **FEMA IS 100, 200, 700, 800**: These incident command system fundamentals and basics are delivered to all IMT/IST personnel and completion is tracked using IMT training materials and attendance rosters. This standard training introduces personnel to the concepts of organized emergency response.
- **ICS 300**: This course provides an in-depth focus on the NIMS ICS including the tools, practices, and procedures that are available in ICS to effectively manage emergency incidents or planned local events at a local Type 3 level. Expanding upon ICS-100 and -200, this course validates that responders understand the basic ICS concepts that allow an incident management organization to expand and contract as needed to fit the incident and maintain operational effectiveness. ICS 300 is delivered to all IMT/IST personnel and completion is tracked using IMT training materials and attendance rosters.
- **PSPS General Training**: This course provides hazard-specific information to new IMT members. It reviews the interdependencies of the different positions on the team and how the key functions are executed in PSPS incidents and activations. Completion is tracked online.

- **PSPS Position-Specific Training**: These courses provide IMT and IST members with an understanding of the position-specific duties, responsibilities, and capabilities of their positions. The courses provide information on their role and information on how to successfully execute on their role during all types of incidents. PSPS Position/Function Specific courses include Ops/Task Force, Incident Commander, Planning Section Chief, CS Branch Director, AFN Supervisor, Customer Care Supervisor, and PSPS Notifications.
- **PSPS Patrolling & Live Field Observation (LFO) Orientation for Contractors**: SCE does not provide training directly to its Contract Field Workforce. Instead, SCE provides orientation on PSPS patrolling and LFO protocols, including any updates since the prior year's training, via Train-the-Trainer sessions for contractor Supervisors. Contractor Supervisors then train their own field crews and submit attendance rosters to SCE. These trainings are conducted annually for all line contract workers and provide awareness of the WMP, PSPS Incident Management, Circuit Switch Plans (to minimize customer impact), updates to the "Operation of Circuits Traversing High Fire Risk Areas" procedure, patrolling scenarios under various operating conditions, timing of LFO deployment, PSPS Field Tools, communication protocols when hazardous conditions exist, and various patrolling scenarios.
- SCE also requires SEMS G606 (Standardized Emergency Management System Introduction Online Course) for IMT, IST, and Pool Positions. Selected IMT/IST positions are also required to take G197 (G197 Integrating Access & Functional Needs into Emergency Management).

11.2.1.3 Memorandums of Agreement

Coordination and collaboration with Public Safety Partners is discussed in Section 11.3.1 Communication Strategy with Public Safety Partners.

Notification of and communication to customers before, during and after a wildfire or PSPS event is discussed in Section 11.4 Public Communication, Outreach, and Education Awareness.

Mutual Assistance Agreements
SCE participates in mutual assistance agreements at the State, Regional and National levels.

State-level mutual assistance is requested when SCE identifies that resource requirements will exceed existing capabilities. SCE will coordinate with in-state utilities through the California Utilities Emergency Association (CUEA) to request resource needs. CUEA is responsible for facilitating mutual assistance requirements between requesting and responding utilities. In the event of statewide resource shortfalls, mutual assistance requests are then escalated to the Western Regional Mutual Assistance Group (WRMAG). WRMAG facilitates mutual assistance coordination at the regional level between member utilities.

A National Response Event (NRE) is when a natural or man-made event causes, or is forecasted to cause, widespread power outages impacting a significant population or several regions across the United States and requires resources from multiple Regional Mutual Assistance Groups (RMAGs). An NRE declaration is made by the Edison Electric Institute (EEI) and is reserved only for events that may result in a widespread power outage, such as a major hurricane, earthquake, or an act of war, impacting industry's mutual assistance efforts.

SCE is also a member of the California Water/Wastewater Agency Response Network (CalWARN). CalWARN supports and promotes statewide emergency preparedness, disaster response, and mutual assistance processes for public and private water and wastewater utilities. SCE has three small water systems: Catalina Island, Mammoth and Bishop.

Aerial Suppression (DEP-5) Memorandums of Understanding (MOUs)

Due to the limited availability of fire suppression resources available statewide, SCE has partnered with local county firefighting agencies since 2019 to create a quick reaction force (QRF) of aerial firefighting resources. Each year, SCE enters memorandums of understanding (MOUs) with Los Angeles, Ventura, and Orange Counties to fund availability of these aerial suppression resources with each fire agency, pursuant to which SCE funded the fixed lease and stand-by time costs for the helicopters, and each fire agency paid for flight time, operational costs, and any other costs (i.e., all variable and non-stand-by costs) when the helicopters were used to fight fires.

Operational decisions regarding where and when the assets are used are at the discretion of the individual fire agencies and are prioritized and deployed by a regional fire coordination center, primarily within the SCE service territory. A regional fire agency coordination center maintains responsibility for directing the aerial suppression resources, using their existing prioritization and deployment process.

In December 2022, SCE entered a funding agreement with Los Angeles, Orange, and Ventura County fire agencies to expand QRF coverage from 165-days to year-round. SCE continues to monitor funding and access to aerial suppression resources in SCE's service territory to determine the need for continued investment in this area. Although the fire suppression assets are intended primarily for use in fighting wildfires in SCE's service territory, SCE relies on the professional judgment of the agencies to inform day to day operations, including determining how and when to deploy the assets. There have been no modifications to the scope of the MOUs since the last WMP submission.

11.2.1.4 Gaps and Limitations in Evaluating, Developing and Integrating Wildfire and PSPS Specific Preparedness and Planning

SCE's emergency preparedness and response plans consider numerous hazards that have been identified as potentially impacting the SCE's service territory and the grid, including wildfire and PSPS. These plans are developed to streamline SCE response efforts, inform critical actions and decision-making, determine roles and responsibilities of SCE first responders, and maximize SCE's ability to respond and recover following any type of disruptive incident. Currently, SCE has not determined any gaps or limitations in integrating wildfire and PSPS planning into its emergency planning. Therefore, SCE did not include any rows to Table 11-2.

Table 11-2: Key Gaps and Limitations in Integrating Wildfire- and PSPS-Specific Strategies into Emergency Plan

Gap or Limitation Subject	Brief Description of Gap or Limitation	Remedial Action Plan
None	N/A	Strategy: N/A Target timeline: N/A

11.2.2 Planning and Allocation of Resources

The electrical corporation must briefly describe its methods for planning appropriate resources (e.g., equipment, specialized workers), and allocating those resources to assure the safety of the public during service restoration.

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*
- *Restores service*

The narrative for this section must be no more than two pages.

SCE is prepared to respond to natural and human-caused emergencies promptly and effectively and to take all appropriate actions including steps to preserve life, property and infrastructure, and maintain the ability to deliver safe and reliable electricity. During an incident within the SCE service territory, SCE coordinates with a diverse set of internal and external stakeholders. For incidents when SCE internal capabilities are overwhelmed, mutual assistance resources are requested and incorporated into the incident organizational structure following the same ICS and NIMS principles for internal SCE resources.

11.2.2.1 Preposition Manpower and Equipment

A coordinated emergency response relies heavily on comprehensive situational awareness, and the response operations to an emergency event require the most up-to-date information available. SCE uses in-house meteorologist staff, data analytics, and geospatial tools to create tailored weather service products using field-based weather station information and modeling to inform operational decision making. When severe weather is forecasted, SCE conducts an evaluation of severity using historical response and management judgment to determine the potential intensity and appropriate response. Depending on the severity of the weather forecast and historical risk models, SCE may activate an IMT under unified command and procure additional laydown yards, stage material and equipment and deploy field personnel near the proximity of the anticipated affected areas.

Weather stations are used to provide critical situational awareness for decision-making and help improve weather models. SCE's weather stations provide data points such as temperature measurements, wind speeds, wind direction, dew point, and relative humidity.

SCE monitors and analyzes weather data at the circuits and circuit segments, where available, across HFRA to inform critical operational decisions such as deploying PSPS protocols during elevated weather conditions. SCE uses weather data forecasts to plan resources for storm preparations and storm responses.

When possible, SCE performs pre-patrols of in-scope circuits and deploys field personnel to circuits at risk to monitor real-time weather conditions using handheld weather stations. Pre-patrols may be initiated up to five days in advance of the forecasted event. Pre-patrols are carried out by qualified personnel (e.g., troublemen, senior patrolmen, etc.) to examine SCE assets for any potential concerns that may be exacerbated by the upcoming wind event.

Damage assessment begins immediately following a disruption to services once it is deemed safe. SCE typically mobilizes on-hand and on-call resources immediately following an incident or PSPS event. For large scale events, SCE may use aerial resources to assess damages. SCE prepositions helicopters and field crews to expedite the safe restoration of power to SCE customers who are impacted by PSPS.

11.2.2.2 Restoration Priorities

For wildfire and other outage emergencies, once conditions have abated and damage assessments are available, SCE determines restoration priorities and develops a restoration plan. SCE seeks to protect life safety, the environment, infrastructure, and property as base planning factors for restoration planning. Restoration planning considers technical factors related to impacts such as grid stability, availability of resources and replacement equipment, as well as internal and external dependencies. SCE may employ different restoration strategies based on the size, scope, complexity, and intensity of each incident. In smaller, more isolated incidents, SCE typically employs the standard order-based strategy that is used under routine outage circumstances. This strategy is not effective in larger incidents where there is an overwhelming volume of orders. When incidents are larger, SCE moves to an area-based strategy where repair priorities are assigned by areas and circuits. This is a tactical decision made during the planning process for a given operational period. The two strategy types, order and area-based can be used together within an event as needed. For PSPS events, restoration planning commences upon activation and restoration activities are triggered by the IC’s approval to re-energize.

Due to the wide range and nature of incidents, SCE has identified guidelines to restore both the most critical and the largest numbers of customers as quickly as possible, while prioritizing public health and safety. With safety of the public and employees as the priority, the restoration effort needs to be done in the most efficient manner possible while also maintaining critical infrastructure and reputational considerations.

11.2.2.3 Internal and External Communications

SCE’s Watch Office, Incident Commander, Public Information Officer, Liaison Officer, Operations Section Chief, and Customer Care Branch Director all work together to coordinate internal and external facing communication and messaging.

SCE discusses how facilitation of external communication in Section 11.3 External Collaboration and Coordination.

11.2.2.4 Restores Service

Once the threat to public safety has abated and the hazardous weather conditions have subsided, SCE coordinates restoration activities, including circuit patrols by field personnel to identify and remediate any potential damage or hazardous conditions. If no damage is found, restoration efforts continue until all customer load is restored. If damage is found, SCE coordinates switching activities to energize as much customer load as possible, and once repairs are completed, restores the remaining customers.

11.3 External Collaboration and Coordination

11.3.1 Communication Strategy with Public Safety Partners

The electrical corporation must describe at a high level its communication strategy to inform external public safety partners and other interconnected electrical corporation partners of wildfire, PSPS, and re-energization events as required by GO 166 and Public Utilities 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 (e.g., fire, law enforcement, OES, municipal governments, Energy Safety, CPUC, other electrical corporations) at every level of administration (state, county, city, or Tribal Nation) as needed*

- *Key protocols for ensuring the necessary level of voice and data communications (e.g., interoperability channels, methods for information exchange, format for each data typology, communication capabilities, data management systems, backup systems, common alerting protocols, messaging), and associated references in the emergency plan for more details*

- *Frequency of prearranged communication review and updates*

In a separate table, the electrical corporation must list the current gaps and limitations in its public safety partner communication strategy coordination. Where gaps or limitations exist, the electrical corporation must indicate the remedial action plan and the timeline for resolving the gaps or limitations. For all requested information, the electrical corporation must indicate a form of verification that can be provided upon request for compliance assurance.

Table 11-3 and Table 11-4 provide the required format and examples of the minimum level of content and detail required.

SCE's procedures are designed to comply with the applicable PSPS regulatory Compliance Requirements, which require SCE to have a PSPS Communications Strategy, and to improve the effectiveness of SCE's PSPS communications and engagement with all stakeholder groups during PSPS events, including those stakeholder groups that are concurrent with other emergencies.

This strategy outlines the multiple approaches and channels used for PSPS event planning and execution and addresses the company's effort to:

- Communicate with customers, non-account holding residents or transients, public safety partners, local jurisdictions, tribal nations, and community members before, during and after PSPS events.
- Conduct broader PSPS education and outreach to customers, communities, and critical infrastructure/facilities to improve resiliency during PSPS events including those events where traditional communications might be restricted through a loss of power.
- Collaborate with public safety partners and communicate with a variety of audiences, including the media. These efforts are aimed at maintaining public safety in accordance with PSPS Compliance Requirements in CPUC D.19-05-042 Decision Adopting De-Energization (PSPS) and subsequent decisions.

SCE provides multiple notifications to stakeholder groups including local governments, tribal governments, first responders, critical infrastructure owners, and other public safety partners before, during, and after a potential PSPS event via email, text, and voice call according to the recipient's preferences.

SCE works with local governments and CalOES to align PSPS communications and regularly meets with county operational areas after major PSPS events, identifying opportunities to improve communication.

SCE's protocol outlines the process to mitigate, plan for, respond to, and recover from a PSPS event that is activated in response to elevated or extreme fire weather in designated HFRA. This protocol includes the use of the ICS to coordinate critical response and recovery operations and the use of an IMT to execute PSPS events.

PSPS decisions are based on quantitative analyses while accounting for qualitative factors, such as societal and emergency management impacts as detailed below. SCE makes PSPS decisions predominantly at the distribution grid level.

For more information on SCE's procedures and protocols, see supporting documents at https://www.sce.com/wmp.

- PSPS Stakeholder Engagement and Communication Strategy (PSPS-04-BR-01), Version 2, September 1, 2024
- PSPS Protocol (PSPS-06-SCE-01), Version 5, June 1, 2024

See Table 11-3 for High-level communication protocols, procedures, and systems with Public Safety Partners. See Table 11-4 for key gaps and limitations in communication coordination with Public Safety Partners.

Table 11-3: High-Level Communication Protocols, Procedures, and Systems With Public Safety Partners

Public Safety Partner Group [1]	Name of Entity [1]	Key Protocols [2]	Frequency of Prearranged Communication Review and Update [2]
See individual line items in full table	See individual line items in full table	• Update contact lists of public safety • Take actions to address any problems or deficiencies identified during an exercise • Business contact to be sent a message according to enrolled channel preference(es) (SMS, email, call) • Messages sent to inform of potential PSPS events and actual de-energizations and re- energizations: ○ Initial ○ Update ○ Expected Shutoff ○ Shutoff ○ Imminent Restoration ○ Restoration ○ Event Concluded • Undeliverable contacts will be reviewed and updated	Ad hoc

This table is provided in full at https://www.sce.com/wmp.

[1] See individual line items for contact information

[2] Information applies to all rows within entire column

Table 11-4: Key Gaps and Limitations in Communication Coordination with Public Safety Partners

Gap or Limitation Subject	Brief Description of Gap or Limitation	Remedial Action Plan
SCE Public Safety Partner Portal	The SCE Public Safety Partner Portal is the best source of information for public safety partners during events as it is automatically updated and kept current. However not all eligible partners are taking advantage of this tool to keep apprised of PSPS data in their jurisdictions.	**Strategy:** Continue Portal office hours (once a month from April through the end of the fire season or December, whichever ends first) to support new user sign up and navigation, and support existing users, as well as ad hoc training sessions as requested. Additionally, promote portal participation to eligible jurisdictions through jurisdictional meetings conducted by local public affairs Government Relations Managers, and Customer Service. Target timeline: Ongoing

11.3.2 Collaboration on Local and Regional Wildfire Mitigation Planning

In this section, the electrical corporation must provide a high-level overview of its plans, activities (programs), and/or policies for collaborating with communities on local and regional wildfire mitigation planning (e.g., wildfire safety elements in general plans, community wildfire protection plans, 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, regional entities/task forces, and non- governmental organizations (e.g., nonprofits, fire safe councils) within the service territory with which the electrical corporation has collaborated or intends to collaborate on local wildfire mitigation planning efforts (i.e., non-wildfire emergency planning activities).*
    - *For each entity, the local or regional wildfire mitigation planning program/plan/document, level of collaboration (e.g., meeting attendance, verbal or written comments, data sharing, risk assessment), and date the electrical corporation provided its last feedback. Table 11-5 provides an example of the minimum acceptable level of information. The electrical corporation must reference the 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 and regional partners on local wildfire planning efforts. Where gaps or limitations exist, the electrical corporation must indicate proposed means and methods to increase collaborative efforts. Table 11-6 provides an example of the minimum acceptable level of information.*

Overview of plans, activities (programs), and/or policies for collaborating with communities on local and regional wildfire mitigation planning.

As discussed in Section 11.2.1 Overview of Wildfire and PSPS Emergency Preparedness and Service Restoration, SCE's AHP articulates the operations and policies that guide how the company prepares for, responds to and recovers from emergency electrical incidents using the utility-specific ICS. The AHP outlines the communications strategy and notification procedures that SCE uses to communicate with its customers, the public, appropriate government agencies, essential service providers, critical care customers, and other important stakeholders in the restoration process. The AHP also outlines how SCE will collaborate with the communities that SCE serves in preparing for and responding to emergency events, which may include activities such as pre-positioning of field resources or equipment in advance of forecasted weather events.

An important component to the AHP is the California Standardized Emergency Management System (SEMS). The SEMS is a structure for coordination between the government and local emergency response organizations. SEMS provides and facilitates the flow of emergency information and resources within and between the organizational levels of field response, local government, operational areas, regions, and state emergency management. SCE has integrated SEMS into its emergency plans and response structure.

During an incident, SCE aligns its response with affected agencies. Coordination with affected agencies requires SCE to engage stakeholders for collaboration, creating a process to request agency representation during an incident or event, and implementing an IMT structure to manage an incident.

Collaboration in Local and Regional Wildfire Mitigation Planning

Below in Table 11-5, SCE lists information on collaboration with community partners.

Table 11-5: Collaboration in Local and Regional Wildfire Mitigation Planning

Name of County, City, or Tribal Agency or Civil Society Organization (e.g., nongovernmental organization, fire safe council)	Program, Plan, or Document	Last Version of Collaboration	Level of Collaboration
Colton	General WMP Plan and PSPS	2023-2025 WMP	SCE + Colton PSPS update meeting
Jurupa Valley	General WMP Plan and PSPS	2023-2025 WMP	Mayor Requesting PSPS Outreach to a Senior Community
San Bernardino County	General WMP Plan and PSPS	2023-2025 WMP	Crest Forest & Lake Arrowhead MAC meeting presentation – WMP / PSPS
Mono County	General WMP Plan and PSPS	2023-2025 WMP	PSPS post-event Government Briefings
Full table is included in Appendix F: Supplemental Information			

Below in Table 11-6, SCE lists information on gaps and limitations in collaborating with community partners.

Table 11-6: Key Gaps and Limitations in Collaborating on Local and Regional Wildfire Mitigation Planning

Subject of Gap or Limitation	Brief Description of Gap or Limitation	Strategy for Improvement
Community Informational Access	Perceived inaccurate or incomplete outage or restoration information available.	**Strategy:** SCE is working on expanding outreach efforts to more localized markets to additional social media platforms and continuing to develop ads with relevant messaging. **Target timeline:** Ongoing.
Local Officials' Informational	Local jurisdictions' limited knowledge of SCE's process in determining circuits in scope for PSPS, de-energization, and re-energization.	**Strategy:** Invite local jurisdiction to participate in SCE's functional annual exercise to gain insight on SCE's PSPS process. Encourage enrolling for the Public Safety Partner Portal (PSPP). **Target timeline:** SCE will conduct a PSPS Operations based exercise annually.

11.3.3 Collaboration with Tribal Governments

In this section, the electrical corporation must provide a high-level overview of its plans, activities (programs), and/or policies for collaborating on local wildfire mitigation planning with tribal governments served by the electrical corporation and on whose lands its infrastructure is located. The narrative must be no more than one page.

In addition, the electrical corporation must provide the following information in tabular form, with no more than one page of tabulated information in the main body of the Base WMP and the full table in an appendix as needed.

- *List of tribal governments served by the electrical corporation and on whose lands its infrastructure is located with which the electrical corporation has collaborated or intends to collaborate on local wildfire mitigation planning efforts (i.e., non-wildfire emergency planning activities).*
    - *For each entity, the local wildfire mitigation planning program/plan/document, level of collaboration (e.g., meeting attendance, verbal or written comments), and date the electrical corporation provided its last feedback. Table 11-7 provides the required format and an example of the minimum acceptable level of information. The electrical corporation must reference the 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 11-8 provides the required format and an example of the minimum acceptable level of information.*

SCE holds meetings and workshops to inform and educate stakeholders and customers about SCE's Grid Hardening activities, wildfire, PSPS, customer programs, and resources available to assist customers with emergency preparedness.

This information helps customers and communities to become better prepared for SCE's wildfire mitigation work and PSPS events. Annually, in advance of fire season, SCE sends informational materials to every local and tribal government in HFRA to provide updates on WMP activities and PSPS protocols. In this outreach, SCE requests emergency contact updates and feedback on Community Resource Center (CRC) locations and services. Additionally, SCE offers to meet with every local and tribal government in HFRA to review the information in person.

SCE provides tours of the Emergency Operation Center (EOC) periodically throughout the year to give tribal leaders a behind the scenes look and to provide more of an understanding of the decision-making process for a PSPS event.

Table 11-7: Collaboration with Tribal Agencies

Name of County, City, or Tribal Agency or Civil Society Organization (e.g., nongovernmental organization, fire safe council)	Program, Plan, or Document	Last Version of Collaboration	Level of Collaboration
Tribal Government	2025 SCE Tribal Engagement Plan	2025 version February 12, 2025	Meeting with Tribal Council to go over their section of the engagement plan is ongoing
Tribal Government and Staff	SoCal Tribal Emergency Managers Group	Quarterly Meetings, November 14, 2024	Active participation and attendance at group meetings and SCE staff provides updates regarding PSPS and resiliency and resources
Tribal Government and Staff	SCE PSPS Critical Infrastructure Workshop	Annual meeting, April 11 and May 29, 2024	Tribal contacts are invited to all PSPS Critical Infrastructure workshops
CA Tribal Electric Leaders	CA Tribal Leaders Energy Summit	Annual meeting, August 27-28, 2024	Tribal electric leaders are invited to collaborate on energy related items

Table 11-8: Key Gaps and Limitations in Collaborating with Tribal Agencies

Subject of Gap or Limitation	Brief Description of Gap or Limitation	Strategy for Improvement
Meeting with Tribal Council	Despite two attempts each year to meet with tribal council groups in our service territory, we sometimes do not get feedback from them.	**Strategy**: SCE will continue to offer to meet with tribal leaders directly or via video call. Target timeline: Biannually.
Points of contact changes	SCE has inconsistent points of contact for tribal agencies due to tribal agency leadership turnover.	**Strategy**: SCE will continue to educate new points of contact on new CPUC rulings, SCE policies, etc. Target timeline: Ongoing.

11.4 Public Communication, Outreach, and Education Awareness

The electrical corporation must describe at a high level its comprehensive communication strategy to inform essential customers and other stakeholder groups of wildfires, outages due to wildfires, and PSPS and service restoration, as required by Public Utilities 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 Public Utilities Code section 768. emergency preparedness plan to provide more detail. The narrative must be no more than one page.

In the following sections, the electrical corporation must provide an overview of the following components of an effective and comprehensive communication strategy:

- *Protocols for emergency communications*
- *Messaging*
- *Outreach and education awareness program(s) for wildfires, PSPS events, and PEDS; service restoration before, during, and after incidents; and vegetation management*
- *Current gaps and limitations*

The electrical corporation must reference the Tracking ID where appropriate.

As discussed above, SCE's AHP outlines the communications strategy and notification procedures SCE uses to communicate with its customers, the public, appropriate government agencies, essential service providers, critical care customers, and other important stakeholders before and during an emergency and during the restoration process.

11.4.1 Protocols for Emergency Communications

The electrical corporation must identify the relevant stakeholder groups and target communities in its service territory and describe the protocols, practices, and procedures used to provide notification of wildfires, outages due to wildfires and PSPS, and service restoration before, during, and after each incident type. Stakeholder groups and target communities include, but are not limited to, the general public; priority essential services[190]; AFN populations and other vulnerable or marginalized populations; populations with limited English proficiency; Tribal Nations; and people in remote areas. The narrative must include a brief discussion of the decision-making process and use of best practices to ensure timely, accurate, and complete communications. The narrative must be no more than one page.

In addition, the electrical corporation must summarize the interests or concerns each stakeholder group/target community may have before, during, or after a wildfire or PSPS event to help inform outreach and education awareness needs. Table 11-9 provides the required format for this summary.

During a wildfire response, the SCE EOC is responsible for ensuring information sharing across all internal and external stakeholders. The EOC typically serves as the interface between SCE, public sector emergency management, regulatory agencies, and elected officials.

Messaging by an IMT is managed by the Public Information Officer (PIO) for distribution to external and internal stakeholders. This inclusive messaging is led, developed, and managed by the PIO and distributed during a crisis to stakeholders throughout the company to use. All IMT messaging is developed by the PIO, in coordination with key members of the IMT and/or IST, and must be approved by the Incident Commander prior to release.

SCE.com is a resource provided by SCE for residents and stakeholders and includes current outage information. The website contains an outage map that is kept updated and is searchable by address and includes current estimated restoration times, when available.

In certain situations, SCE cannot provide notifications prior to an emergency due to the unexpected nature of the incident. During an emergency that results in a power outage, SCE provides notifications that inform the public of the estimated restoration times and potential safety hazards. Once the threat to public safety has abated, hazardous weather conditions have subsided and power has been restored, customers will be informed when power has been restored.

For PSPS, SCE has established a coordinated and cohesive messaging protocol that provides priority notifications to Public Safety Partners, critical facilities and infrastructure customers, and transmission customers. Prior to a PSPS event, SCE sends initial notification of a potential PSPS event when circuits are first identified for potential de-energization. During a PSPS event, PSPS event status update notifications are sent to alert for any changes or additions/deletions to current scope (timing varies and may also occur daily). An update notice to Public Safety

190 Priority essential services include but are not limited to public safety offices, critical first responders, health care facilities and operators, and telecommunications infrastructure and operators.

Partners may also serve as a cancellation notice if circuits are removed from scope. If de-energization is expected, SCE sends expected power shut off notifications 1-4 hours before potential de-energization. Another notification is sent when power has been shut-off. After a PSPS event, when SCE is preparing to restore power, customers receive notifications that inspection/patrols of de-energized circuits for PSPS restoration has begun and power will be restored shortly. Another notification is provided when power has been restored, and the customer is no longer in scope for this event. If customers were not de-energized during a PSPS event, customers will receive a cancellation notice indicating no de-energization is expected.

In PSPS customer notifications, SCE directs potentially impacted customers to www.sce.com/psps for information related to the location, hours, and services available at CRCs. Instructions on where customers can access electricity during the hours the centers are closed have been made available on the SCE website to facilities and infrastructure customers, and transmission-level customers, which complies with all standard emergency alerting and warning protocols.

SCE continues to partner with multiple agencies and organizations to educate, provide outreach, obtain feedback, and develop solutions to customer concerns related to PSPS. An insufficient advance notice can result in customers and the public not being adequately prepared; therefore, SCE continues to enhance processes and technology to improve the timeliness, effectiveness, and accuracy of notifications.

The Emergency Outage Notifications System (EONS) is the primary tool used to keep customers informed before, during, and after wildfire and PSPS events. EONS allows SCE to communicate to all customer classes (receiving under 66kv power) impacted by wildfire and PSPS via email, voice calls, and/or SMS. PSPS notification translations are available in 23 languages (see Section 11.4.2).

In order to help ensure best practices and continuous improvement, impacted State and County emergency management agencies and critical infrastructure customers are polled in a survey at the close of each PSPS event to provide feedback. SCE also conducts annual pre- and post-season surveys to evaluate the effectiveness of its wildfire safety and preparedness communications and outreach to customers in general.

Below, Table 11-9 provides the interests or concerns each stakeholder group/target community has before, during, or after a wildfire or PSPS event.

Table 11-9: Protocols for Emergency Communication to Stakeholder Groups

Stakeholder Group/Target Community	Event Type	Method(s) for Communicating	Means to Verify Message Receipt	Interests or Concerns Before, During, and After Wildfire and PSPS events
State agencies	PSPS	Twice daily (or more frequently as required by changes in event status) updates to the CalOES notification form. Daily (or more frequently as required by changes in event status) updates to CPUC using email template.	CalOES Submission received notification on online form; updated information and submission number is published on dashboard. CPUC email bounce backs would indicate failure to deliver.	Period of concern, circuits and jurisdictions in scope, customers impacted and de-energized, event stage, estimated restoration time, all clear (event complete).
Public safety partners	PSPS	Information posted on portal: email sent to all partners signed up for portal informing them that new event has been started. Subsequent updates are posted only on the portal and not sent via email.	"Delivery failed" information provided by notification vendor	Period of concern, circuits and jurisdictions in scope, customers de-energized, needs of vulnerable populations, de-energization status, estimated restoration time, all clear (event complete), availability and location of customer resources and AFN support.
Critical facilities and infrastructure customers	PSPS	Delivery notices in recipient's preferred channel: voice, email, SMS	"Delivery failed" information provided by notification vendor.	Period of concern, de-energization status, estimated restoration time, all clear (event complete).
All customers including AFN	PSPS	Delivery notices in recipient's preferred channel: voice, email, SMS	"Delivery failed" information provided by notification vendor	Period of concern, de-energization status, estimated restoration time, all clear (event complete). Availability and location of customer resources and AFN support.
Local governments	PSPS	Delivery notices in recipient's preferred channel: email, SMS	"Delivery failed" information provided by notification vendor	Period of concern, circuit information within their jurisdiction, de-energization status, critical infrastructure in scope, customers de-energized, estimated restoration time, all clear (event complete) availability and location of customer resources and AFN support.
Tribal governments	PSPS	Delivery notices in recipient's preferred channel: email, SMS	"Delivery failed" information provided by notification vendor	Period of concern, circuit information within their jurisdiction, de-energization status, critical infrastructure in scope, customers-energized, estimated restoration time, all clear (event complete), availability and location of customer resources and AFN support.

Stakeholder Group/Target Community	Event Type	Method(s) for Communicating	Means to Verify Message Receipt	Interests or Concerns Before, During, and After Wildfire and PSPS events
Non-customers who signed up for alerts and all other parties	PSPS	Address level alerts: email, SMS and voice Public Safety Portal, SCE.com, social media	"Delivery failed" information provided by notification vendor	Period of concern, de-energization status, estimated restoration time, all clear (event complete).
State agencies	Maintenance or Repair Outage related to Wildfire	Delivery notices in recipient's preferred channel: voice, email, SMS	N/A	Estimated time for power restoration.
Public safety partners	Maintenance or Repair Outage related to Wildfire	Delivery notices in recipient's preferred channel: voice, email, SMS	N/A	Estimated time for power restoration.
Local governments	Maintenance or Repair Outage related to Wildfire	Delivery notices in recipient's preferred channel: voice, email, SMS	N/A	Estimated time for power restoration.
Tribal governments	Maintenance or Repair Outage related to Wildfire	Delivery notices in recipient's preferred channel: voice, email, SMS	N/A	Estimated time for power restoration.
Essential Use Customers	Repair Outage related to Wildfire	Delivery notices in recipient's preferred channel: voice, email, SMS	Verification of receipt of voice communication	Estimated time for power restoration.
Major Customers	Repair Outage related to Wildfire	Delivery notices in recipient's preferred channel: voice, email, SMS	Verification of receipt of voice communication	Estimated time for power restoration.
All customers including Medical Baseline and Critical Care	Repair Outage related to Wildfire	Delivery notices in recipient's preferred channel: voice, email, SMS	Verification of receipt of voice communication	Estimated time for power restoration.
Unassigned/Residential	Repair Outage related to Wildfire	Delivery notices in recipient's preferred channel: voice, email, SMS	Verification of receipt of voice communication	Estimated time for power restoration.
Essential Use Customers	Wildfire – As needed communication	Delivery notices in recipient's preferred channel: voice, email, SMS	Information is available as long as the customer is signed up to receive notifications and there is an emergency preference alert	Estimated time for power restoration.
Major Customers	Wildfire – As needed communication	Delivery notices in recipient's preferred channel: voice, email, SMS	Information is available as long as the customer is signed up to receive notifications and there is an emergency preference alert	Estimated time for power restoration.
All customers including Medical Baseline and Critical Care	Wildfire – As needed communication	Delivery notices in recipient's preferred channel: voice, email, SMS	Information is available as long as the customer is signed up to receive notifications and there is an emergency preference alert	Estimated time for power restoration.
Unassigned/Residential	Wildfire – As needed communication	Delivery notices in recipient's preferred channel: voice, email, SMS	Information is available as long as the customer is signed up to receive notifications and there is an emergency preference alert	Estimated time for power restoration.

11.4.2 Messaging

In this section, the electrical corporation must describe its procedures for developing effective messaging to reach the largest percentage of stakeholders in its service territory before, during, and after a wildfire, an outage due to wildfire, or a PSPS event.

In addition, the electrical corporation must provide an overview of the development of the following aspects of its communication messaging strategy:

- *Features to maximize accessibility of the messaging (e.g., font size, color contrast analyzer)*
- *Alert and notification schedules*
- *Translation of notifications*
- *Messaging tone and language*
- *Key components and order of messaging content (e.g., hazard, location, time)*

The narrative must be no more than one page.

All emergency management communications follow SCE's "One-Voice" communications strategy. This strategy was adopted following the 2011 SCE response to windstorms in our service territory, which requires all communications regarding emergency conditions (e.g. wildfire, windstorms, PSPS) during periods of IMT activation to use messaging provided by the PIO and approved by the IC.

Channels using One Voice messaging include written communications, media outreach, SCE.com, and direct communication with customers (through the call center) and local officials (through liaison officers). One Voice messaging is updated daily or more frequently when there is significant updated information available such as a substantial change in number of customers de-energized.

All messaging is written by PIOs, who are IMT-trained and have received additional specialized PIO and SCE-specific communications training. PIOs all serve in communications roles in their day-to-day roles or have communications backgrounds.

One Voice messaging is adapted by internal users to meet channel requirements. For example, the specific language and format used by social media is not the same as the language and format used in the call center. However, the messages and data remain consistent. Outage communications and PSPS notifications are sent to customers in the format and channel of their preference. PSPS notifications are also available in multiple languages and formats including compliance with Web Content Accessibility Guidelines (WCAG). Please see Section 11.4.3 Outreach and Education Awareness Activities for additional information on these communications and notifications.

PSPS Notifications are written in simplified language with the goal of providing message clarity and actionable information. They are translated into 19 written languages that are prevalent in SCE's service territory (Arabic, Armenian, Chinese Mandarin, Chinese Cantonese, Farsi, French, German, Japanese, Khmer, Korean, Punjabi, Russian, Spanish, Tagalog, Vietnamese, Portuguese, Hindi, Hmong, and Thai) as well as three indigenous spoken languages (Mixteco, Zapoteco, and Purapecha), and American Sign Language (ASL). Static versions of PSPS notifications translated into the prevalent languages can be accessed via SCE's Wildfire Communications Center.[191] PSPS notifications follow the alerts and warnings systems outlined in the California Public Alert and Warning System (CalPAWS) Plan.

Initial PSPS notifications are classified as alerts, in keeping with the definition that alerts "draw the attention of recipients to some previously unexpected or unknown condition or event."[192] Update notifications 24 hours before the onset of the period of concern are classified as warnings, in keeping with the definition that warnings encourage "recipients to take immediate protective actions appropriate to some emergent hazard or threat."[193] Other PSPS notifications, including PSPS Expected, Shutoff, Prepare to Restore, and restoration, are classified as notifications as they are "intended to inform recipients of a condition or event for which contingency plans are in place."[194] These notifications include timing, hazard (PSPS), and are location-specific for each customer. Please see Section 11.4.3 Outreach and Education Awareness Activities for additional information.

11.4.3 Outreach and Education Awareness Activities

In tabulated format, the electrical corporation must provide a list the various outreach and education awareness activities (programs) (i.e., campaigns, informal education, grant programs, participatory learning) that the electrical corporation implements before, during, and after wildfire, vegetation management, and PSPS events to target communities, including efforts to engage with partners in developing and exercising these activities (programs). Table 11-10 provides the require format and an example of the minimum acceptable level of information. 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.

SCE holds various meetings, workshops, and events to inform and educate stakeholders and customers about Grid Hardening activities, wildfire, PSPS, customer programs, and resources available for emergency preparedness. This helps customers and communities become better prepared for PSPS events. SCE sends informational materials to local and tribal governments in HFRA before fire season, requesting emergency contact updates and feedback on Community Resource Center (CRC)/Community Crew Vehicle (CCV) locations and services.

SCE also meets with County Operational Areas to review PSPS protocols and decision-making factors, AFN outreach, and other emergencies like fires and storms. Quarterly regional Working Group meetings are held with local governments, critical infrastructure providers, and organizations serving the AFN community to review best practices and

191 *See* https://www.sce.com/wildfire/wildfire-communications-center.

192 *See* https://calalerts.org/documents/calpaws/01California-State-Warning-Plan.pdf.

193 *Id.*

194 *Id.*

lessons learned related to wildfire, PSPS, and outage management. Workshops with critical infrastructure customers provide an overview of PSPS and wildfire mitigation and how they can enhance their resiliency in a PSPS event.

SCE participates in safety fairs in HFRA communities to help customers prepare for potential PSPS, updating customer contact information, enrolling customers in outage alert notifications, and sharing information on resiliency programs and community resources.

SCE partners with Community Based Organizations (CBOs) to conduct in-language wildfire safety/PSPS preparedness customer education and outreach, with a focus on high fire risk areas. Incentivized partnerships with CBOs help educate and increase awareness around wildfire and safety preparedness, sharing information about SCE's WMP, resiliency plans, and assistance programs like MBL, California Alternate Rates for Energy (CARE)/Family Electric Rate Assistance (FERA), rate options, portable power station and generation rebates, battery storage, and Critical Care Backup Battery (CCBB). CBOs track their outreach and engagement efforts, submitting monthly reports to evaluate performance and program effectiveness.

SCE sends a bi-lingual letter and flyer annually to master-metered customers to educate their sub-metered tenants about wildfire/PSPS information, including preparation steps and safety during a PSPS outage. Electronic copies of the flyer are available in multiple languages on SCE's Wildfire Communications Center on SCE.com.

11.4.3.1 Advertising and Marketing Campaign

SCE's ongoing advertising campaign includes radio, digital, social media, billboard, search ads, and direct customer mailings to educate customers and the public on PSPS, wildfire mitigation, emergency preparedness, and customer programs and resources. Ads are available in 19 languages, and total impressions are tracked.

SCE also implements a customer-centric, integrated marketing campaign to deliver consistent messaging across traditional and digital channels, driving Wildfire/PSPS customer education and proactive preparedness behavior. Customers are placed into specific segments, and journeys are designed relevant to each segment before, during, and after a PSPS event. PSPS preparedness messaging is amplified through inclusions and cross promotions in other integrated communications. Marketing technology solutions prevent customers from receiving conflicting messaging by improving coordination between PSPS notification and standard customer communications systems.

SCE's integrated marketing campaign includes its PSPS Newsletter, which is emailed annually to all customers in both HFRA and non-HFRA regions with tailored content. The HFRA version highlights wildfire mitigation efforts and PSPS impacts, while the non-HFRA version emphasizes outage safety tips and emergency preparedness. Electronic copies of both newsletter versions are available in English and 19 prevalent languages on SCE's Wildfire Communications Center on SCE.com.

11.4.3.2 Community Meetings (DEP-1)

SCE holds wildfire safety community meetings throughout SCE's service territory, prioritizing HFRA, to share information about SCE's wildfire mitigation plan, grid hardening updates, PSPS, emergency preparedness, and an additional focus on SCE's programs, services, and resources. These meetings offer participants a chance to ask questions of

SCE staff and share feedback and concerns. For 2026-2028, SCE will host a minimum of two virtual wildfire community safety meetings annually, with the ability to host up to nine wildfire community safety meetings annually to focus on PSPS, wildfire emergencies, and community needs. Additional meetings will be hosted based on PSPS activity and/or community needs as they arise.

11.4.3.3 Customer Research and Education (DEP-4)

SCE seeks to improve its understanding of how to reduce impacts of wildfires, PSPS, and wildfire mitigation work for its customers. SCE develops surveys to capture customer feedback on SCE's wildfire mitigation initiatives with a special emphasis on PSPS activities. Specific activities as part of this customer research and education initiative are detailed below:

- The PSPS Tracker is an annual survey conducted at the end of wildfire season (Q1 of the following year) to assess and understand customer awareness, experience, and opinions of SCE's PSPS and wildfire mitigation activities, focusing on customers affected by PSPS events. Four customer segments are targeted:
- Customers notified and de-energized
- Customers notified but not de-energized
- Customers not notified and not de-energized
- Customers who do not live in a HFRA
- CRC/CCV safety community meeting surveys conducted among attendees of the meetings to receive feedback on their experience and the information provided.
- CRC/CCV visitor surveys conducted among customers who visited a CRC/CCV during a PSPS event to receive feedback on their experience, and the resources and support provided.
- In-Language Pre-/Post- Wildfire Mitigation Communications Effectiveness Surveys (mandated since 2020) that measure the communications and outreach effectiveness prior to and coincident with/after the wildfire seasons in English and 19 non-English prevalent languages.

For 2026-2028, SCE will continue to conduct these surveys to bolster our assessment of customer attitudes, perceptions, and behaviors towards wildfire mitigation programs and PSPS events.

If factors outside of SCE's control allow for execution of additional surveys, SCE will strive to conduct up to five wildfire mitigation/ PSPS-related customer studies. Additional surveys will be conducted based on PSPS activity and/or community needs as they arise.

Below in Table 11-10 is a summary of Target Communities and their interests/concerns before, during, or after a wildfire or PSPS event.

Table 11-10: List of Target Communities

<table>
<tr><th>Target Community</th><th>Interests or Concerns Before, During, and After Wildfire and PSPS events</th></tr>
<tr><td>Individuals who have developmental or intellectual disabilities</td><td>

Access to electrically powered durable medical equipment or assistive technology used for health, safety, and independence (e.g., Augmentative and Alternative Communication devices)
Access to information that can be understood
Access to transportation on demand (e.g., paratransit or accessible transportation)

Examples of offerings to mitigate impact:

For customers who reside in HFRA, SCE offers the following:

Battery and generator rebates for assistive technology or other devices
Batteries for short term and long-term loans for customers who rely on electricity
Batteries free of charge to customers enrolled in the MBL
SCE offers notification/alerts in English (translated into prevalent languages) and address level alerts that can be used by anyone, including caregivers.

SCE partners with a third-party vendor to translate notifications/alerts in American Sign Language with English voice over and text that is accessible via screen readers and Braille readers.
SCE partners with CBOs such as the California Foundation for Independent Living Centers, and 211 California Network to connect customers to transportation. Additionally, SCE continues expanding partnerships and accessible transportation options.
SCE partners with Community Based Organizations that serve individuals with AFN to help with wildfire safety education and outreach.
</td></tr>
<tr><td>Individuals who have physical disabilities</td><td>

Access to electrically powered durable medical equipment or assistive technology used for health, safety, and independence (e.g., motorized scooter)
Access to information that can be understood (e.g., American Sign Language)
Access to transportation on demand (e.g., paratransit or accessible transportation)

Examples of offerings to mitigate impact:

For customers who reside in HFRA, SCE offers the following:

Battery and generator rebates for assistive technology or other devices
Batteries for short term and long-term loans for customers who rely on electricity
Batteries free of charge to customers enrolled in the MBL

SCE offers notification/alerts in English (translated into prevalent languages) and address level alerts that can be used by anyone, including caregivers.
SCE partners with a third-party vendor to translate notifications/alerts in American Sign Language with English voice over and text that is accessible via screen readers and Braille readers.
SCE partners with CBOs such as the California Foundation for Independent Living Centers, and 211 California Network to connect customers to transportation. Additionally, SCE continues expanding partnerships and accessible transportation options.
</td></tr>
<tr><td>Individuals who have chronic conditions, injuries, or enrolled in the medical baseline program</td><td>

Access to electrically powered durable medical equipment or assistive technology used for health, safety, and independence (e.g., durable medical equipment used for breathing purposes)

Examples of offerings to mitigate impact:

For customers who reside in HFRA, SCE offers the following:

Battery and generator rebates for assistive technology or other devices
Batteries for short term and long-term loans for customers who rely on electricity
Batteries free of charge to customers enrolled in the MBL
SCE partners with Community Based Organizations that serve individuals with AFN to help with wildfire safety education and outreach.

SCE takes additional steps to ensure that MBL and Life Support customers are receiving notifications advising them about a potential PSPS. When SCE does not receive confirmation that these customers received proactive alerts and notifications, SCE will conduct follow-up calls and messages, and finally, send a representative to attempt in-person contact (doorbell ring).
</td></tr>
</table>

Target Community	Interests or Concerns Before, During, and After Wildfire and PSPS events
Limited English proficiencies	• Limited access to understand electrical corporation wildfire hazards and risks, specific actions that can be taken to reduce risk, and awareness of emergency services, resources, etc. Examples of offerings to mitigate impact: • SCE offers notification/alerts in plain English (translated into prevalent languages). • SCE partners with a third-party vendor to translate notifications/alerts in American Sign Language with English voice over and text that is accessible via screen readers and braille readers. • SCE partners with Community Based Organizations that serve individuals with AFN to help with wildfire safety education and outreach.
Children	• Access to information that can be understood. Examples of offerings to mitigate impact: • SCE partners with Community Based Organizations that serve individuals with AFN, including youth-based groups, to help with wildfire safety education and outreach.
People living in institutionalized settings	• Access of information pertaining to wildfire hazards and risks, specific actions that can be taken to reduce risk, and awareness of emergency services, resources, etc. Examples of offerings to mitigate impact: • SCE provides advance notifications to Public Safety Partners and critical infrastructure and keeps them informed of the PSPS. • SCE offers individuals access to address level alerts for PSPS. Any individual can enroll to receive these alerts even if they are not the customer of record.
People who are low income or enrolled in income qualified programs	• Access to resources and food support during a PSPS event Examples of offerings to mitigate impact: • SCE partnered with 211 California Network to assist customers with food needs during and immediately after a PSPS. • SCE is expanding partnerships with local food banks to provide customers affected by PSPS with a food box during or immediately after a PSPS.
People experiencing homelessness	• Access to information pertaining to wildfire hazards and risks, specific actions that can be taken to reduce risk, and awareness of emergency services, resources, etc. • Access to power and cell signal for their mobile devices Examples of offerings to mitigate impact: • SCE provides advance notifications to Public Safety Partners and critical infrastructure and keeps them informed of the PSPS. • SCE offers individuals access to address level alerts for PSPS. Any individual can enroll to receive these alerts even if they are not the customer of record.
People who are transportation disadvantaged, including but not limited to, those who are dependent on public transit	• Access to on-demand transportation for evacuation, or relocation purposes • Access to on-demand transportation to visit community resource centers or community crew vehicles Examples of offerings to mitigate impact: • SCE partnered with CBOs such as CFILC and 211 California Network to assist customers with transportation needs. • SCE provides advance notifications to Public Safety Partners and critical infrastructure (transportation sector is identified as a critical infrastructure) and keeps them informed of the PSPS.

People who are pregnant or nursing babies	• Access to electrically powered durable medical equipment or assistive technology used for health, safety, independence and nursing (e.g., breast pump, air conditioner, or refrigeration for medication, formulas, or breast milk)
	Examples of offerings to mitigate impact:
	• For customers who reside in HFRA, SCE offers the following:
	  • Battery and generator rebates for assistive technology or other devices
	  • Batteries for short term and long-term loans for customers who rely on electricity
	  • Batteries free of charge to customers enrolled in the MBL
	• Customers who have refrigeration needs for medication, formula, or breastmilk can get a small thermal bag and ice voucher at any CRC/CCV that are operating during PSPS.
	• SCE offers a private space at any CRC location that are operating during a PSPS for mothers who are nursing or individuals who need to use medical equipment.

11.4.4 Engagement with Access and Functional Needs Populations

The electrical corporation must provide an overview of its process for understanding, evaluating, designing, and implementing wildfire and outage program risk initiative strategies, policies, and procedures specific to AFN customers across its territory.[195]*The electrical corporation must provide its AFN plan as an attachment and may it to provide more detail. The electrical corporation must also report on the following:*

- *Summary of key AFN demographics, distribution, and percentage of total customer base.*

- *Evaluation of the specific challenges and needs during a wildfire or PSPS event of the electrical corporation's AFN customer base.*

- *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 post for those populations before, during, and after the incidents. This should include high-level strategies, policies, programs, and procedures for outreach, engagement in the development and implementation of the AFN-specific initiative strategies, and ongoing feedback practices.*

The electrical corporation must reference the Tracking ID where appropriate.

Based on 2024 data, SCE estimates that it has over 1.8 million unique customer accounts with AFN, which equates to approximately 39% of total customer accounts. SCE uses an approach consistent with other IOUs to identify and track customers with AFN.

SCE aggregates unique customer accounts enrolled in the following programs to determine the annual number of customers and percentage of accounts:

- **CARE or FERA:** The annual number of income-qualified customers is calculated as the total number of service accounts enrolled in SCE's income qualified programs such as CARE/FERA.
- **Medical Baseline Allowance (MBL) Program:** The annual number of MBL customers is calculated as the total number of customers enrolled in SCE's MBL program.
- **Life Support (Critical Care):** Critical Care customers are a subset of the MBL population. The annual number of Critical Care customers is calculated as the total number of customers who have been identified to use medical equipment for life support purposes, meaning that the customer cannot be without life support equipment for at least two hours.
- **Bill Preferences:** Customers who receive their utility bill in an alternate format (e.g., Braille; large font).
- **Language Preferences:** Limited English proficiency is calculated based on the total number of customers who have self-certified with SCE that their primary language is one other than English.
- **Older adults/seniors:** Customers who have certified as being 65 years old or older.
- **Customers who self-certify:** SCE appends information on customer accounts for households that self-certify as having someone in their household with a condition

195 Pub. Util. Code § 8386(c)(7), (19).

that can be significantly affected by the interruption of power during a PSPS event or a disconnection for non-payment of a bill. The benefit of self-certification, which is good for 90 days, is that in the event of a disconnection, SCE will attempt to reach the customer through their preferred method of contact (email, text, or voice call) to notify them of the outage. If SCE cannot reach the customer through their preferred method, a field service representative will attempt to make in-person contact at the customer's home address to deliver the message regarding the disconnection.

- **Customers who Self-Identify as AFN:** SCE launched an AFN Self-Identification campaign in 2022 to further identify customers and household members with access and functional needs, above and beyond customers enrolled in the Medical Baseline Allowance Program. New customer information gathered through the surveys enables SCE to provide further tailored support to customers who:
- Rely on electrically powered medical equipment
- Need heating and cooling for body temperature regulation
- Rely on assistive technology
- Need refrigeration for a medical purpose
- Need accessible transportation
- Cannot leave home without difficulty
- Are 65 and older
- Have a household member with a disability
- Have language preferences

SCE notes that the data available on individuals with AFN does not cover all categories (e.g., individuals experiencing homelessness or transient populations, or transportation disadvantaged).

Pursuant to D.20-05-051 and D.21-06-034, SCE submits an annual AFN Plan for focuses on mitigating the impacts of a PSPS event on individuals with AFN.[196] The AFN Plan focuses on mitigating the impacts of a power shutoff on individuals with AFN. Quarterly updates are also submitted that measure progress on implementing that plan.

This plan is focused on the specific approach for serving individuals with AFN before, during, and after a PSPS event. It summarizes the research, feedback, and external input that has shaped the support strategy for populations with AFN, the programs that serve these individuals, the preparedness outreach approaches focused on populations with AFN, and the in-event customer support services and programs.

SCE annually conducts a PSPS Tracker Survey, which asks customers who had been in scope of a PSPS in the prior year about their experience and knowledge surrounding PSPS. Additionally, SCE includes AFN demographics questions in the survey to better understand the experience of customers with AFN during a PSPS event.

196 SCE's 2025 AFN Plan, available at https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M555/K961/555961239.PDF.

Table SCE 11-02: PSPS Tracker Survey Key Findings and Mitigation Measures for Customers With AFN

Key Findings	Mitigation Measure(s)
Awareness and satisfaction with the perceived availability of resources remain low, though interest in receiving them is higher than before. • Additionally, few customers with AFN are aware of SCE's community partnerships, such as 211, food pantries, and paratransit agencies, which assist during a PSPS. • Access to resources during a PSPS is crucial for customers with AFN, yet just over half are aware of what SCE provides, indicating opportunity for SCE to improve resource awareness.	Leveraging data obtained through the AFN self-identification survey, in 2023, SCE began conducting personalized marketing and outreach to a small pilot audience of newly identified customers with AFN through the AFN Marketing Nurture Campaign. In 2024, SCE integrated the AFN Nurture Campaign into the larger PSPS Preparedness journey experience to maximize efficiency and reduce email fatigue. In 2025, SCE will continue to implement an integrated Preparedness Journey marketing campaign, which highlights programs including 211.org and Disability Disaster and Access Resource (DDAR). In addition, SCE will continue providing customers with information and resources in partnership with CBOs, through the accessible statewide website PrepareForPowerDown.com, and on www.sce.com/afn.
Interest in emergency resources and dedicated support during a PSPS is high among de-energized customers with AFN: • This year, customers with AFN showed increased interest in emergency battery loans during a PSPS and are more likely than customers without AFN to want a dedicated customer service representative for households with disabilities during a PSPS.	SCE provides several options that allow customers to use medical equipment with a portable backup battery through the CCBB or to request a battery on loan through the In-Event Battery Loan pilot. During PSPS, SCE has a dedicated AFN supervisor to provide support for customers with AFN. Additionally, SCE partners with CBOs such as 211 and DDAR who provide in-event support services.

For a full list of key findings and mitigation measures, please see SCE's 2025 AFN Plan.

11.4.5 Engagement with Tribal Nations

The electrical corporation must provide an overview of its process for understanding, evaluating, designing, and implementing wildfire and outage program risk initiative strategies, policies, and procedures specific for collaboration with to Tribal Nations served by the electrical corporation and on whose lands its infrastructure is located. The electrical corporation must also report on the following:

- *Summary of key tribal demographics*
- *Ongoing consultation and collaborative efforts performed by the electrical corporation with Tribal Nations*
- *Evaluation of the specific challenges and needs during a wildfire or PSPS event of the electrical corporation's Tribal Nation customer base*
- *Plans to address specific needs of the tribal customers throughout the service territory specific to the unique threats that wildfires and PSPS events may pose for those populations before, during, and after the incidents. This should include high-level strategies, policies, programs, and procedures for outreach, engagement in the development and implementation of the tribal-specific risk initiative strategies, and ongoing feedback practices*

The electrical corporation must reference the Tracking ID where appropriate.

There are 13 federally recognized tribal nations within SCE's service territory.[197] Within SCE's tribal engagement plan, SCE sends out consultation requests each year, once in Q1 and another in Q3. When a tribe agrees to meet with SCE, SCE presents on several topics, including its wildfire mitigation efforts and PSPS. These in-person consultations are also an effective way for SCE to understand any operational or other issues that affect these tribes.

Protocols for emergency notifications to tribal customers are the same as non-tribal community notifications with one caveat. Some tribes have their own separate notifications process for emergencies using text or email software. SCE has a two-year tribal engagement plan that is updated after the second year. The plan calls for in-person tribal council engagement at least once a year. SCE relies heavily on text and emails to communicate with tribal staff and if for some reason communication ceases, SCE will go to the reservation and speak to tribal government staff members to ensure proper points of contact. SCE has been asked to attend in-person tribal citizen meetings and have attended Earth Day events to ensure there is some level of tribal citizen engagement.

Overall, tribes report to SCE that they feel they get emergency notifications, including for PSPS, in a timely manner that gives the tribe time to communicate directly to its community

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197 SCE serves 13 federally recognized tribal nations: Agua Caliente Band of Cahuilla Indians, Benton Utu Utu Gwaitu Paiute Tribe, Bishop Paiute Tribe, Bridgeport Indian Colony, Chemehuevi Indian Tribe, Colorado River Indian Tribes, Morongo Band of Mission Indians, Pechanga Band of Luiseno Indians, San Manuel Band of Mission Indians, Soboba Band of Luiseno Indians, Timbisha Shoshone Tribe, Tule River Indian Tribe, and Twenty Nine Palms of Band of Mission Indians.

members about any services the tribe offers such as community resource centers and warming or cooling centers.

SCE adds any specific plans for PSPS or other wildfire mitigation issues after consultations with these tribes. Each tribe's concerns are typically handled by SCE's tribal liaison team before a potential PSPS event. SCE re-affirms any new tactic after each PSPS to ensure that the new tactic is effective or if another one needs to be developed and implemented with the tribe's approval.

More information about SCE and tribal nations engagement can be found on SCE's website.[198]

11.4.6 Current Gaps and Limitations

In tabulated format, the electrical corporation must provide a list of current gaps and limitations in its public communication strategy, including any notification failures identified in the most recent PSPS post-season report. Where gaps or limitations exist, the electrical corporation must indicate the remedial action plan and the timeline for resolving the gaps or limitations. For all requested information, the electrical corporation should indicate a form of verification that can be provided upon request for compliance assurance. Table 11-11 provides an example of the minimum level of content and detail required.

Below in Table 11-11 is a summary of SCE's gaps and limitations in public emergency communication strategy.

Table 11-11: Key Gaps and Limitations in Public Emergency Communication Strategy

Gap or Limitation Subject	Remedial Brief Description	Remedial Action Plan
Communication to local officials	In extremely large PSPS events, elected officials want to be kept informed so they can help address constituent questions and concerns.	SCE is establishing protocols for regular briefings for SCE leaders to provide updates to elected officials and their staff during large scale events of significant community interest. This approach was first adopted during the January 2025 PSPS events. SCE expects to finalize 2026-2028 protocols by 6/1/2026.
Customer Communications	Additional information beyond what is provided through templated PSPS notifications is required to inform customers who are impacted by concurrent extreme events (e.g., wildfires or windstorms) during PSPS events.	In January 2025, and for future PSPS events with concurrent outages, SCE will develop supplemental communications templates to keep customers informed about the status of their outage. SCE anticipates completing templates by September 2025.

198 *See* SCE's website for more information on tribal communities, available at https://www.sce.com/partners/partnerships/Tribal-Communities.

11.5 Customer Support in Wildfire and PSPS Emergencies

In this section, the electrical corporation must provide an overview of its activities (programs), systems, and protocols to support residential and non-residential customers during and after wildfire emergencies and PSPS events. The overview for each emergency service must be no more than one page. The overview must cover the following customer emergency services:

- *Outage reporting*
- *Support for low-income customers*
- *Billing adjustments*
- *Deposit waivers*
- *Extended payment plans*
- *Suspension of disconnection and nonpayment fees*
- *Repair processing and timing*
- *List and description of community assistance locations and services*
- *Medical Baseline support services*
- *Access to electrical corporation representatives*

The electrical corporation must reference the Tracking ID where appropriate.

SCE has a dedicated customer support team and a portfolio of services and resources to support customers before, during, and after a PSPS event. Some resources and support services are also available during a major emergency such as CRCs/CCVs, food support, and access to 211 and Disability Disaster and Access Resources (DDAR) programs to facilitate transportation, hotel accommodations, and general in-event support. These services and resources increase customer resiliency and help develop emergency preparedness plans, as well as provide assistance during PSPS and other major emergencies. There are also post-event processes in place to gather feedback and lessons learned. SCE continues to update and enhance its portfolio of offerings, improving on communications to help increase customer safety and mitigate the impacts brought on by PSPS and other emergencies.

SCE directs customers to www.sce.com/outage-map for information related to outages related to PSPS and wildfire, as well as to obtain location information on resources such as CRCs/CCVs, hotel's participating in SCE's hotel discount program, locations for electric vehicle (EV) charging, and food banks. Additionally, SCE describes in detail its strategy to support and engage the AFN community in the 2025 AFN Plan,[199] and in Section 11.4.4.

SCE used the following programs to provide customer support during PSPS and wildfire emergencies: outage reporting, support for low-income customers, billing adjustments, deposit waivers, extended payment plans, suspension of disconnection and nonpayment fees, repair processing and timing, lists and description of community assistance locations and services, medical baseline support services, and access to electrical corporation representatives. These programs are further described below.

To mitigate customer risks that could arise during and after an emergency, SCE uses the following practices and/or enacts customer protections in line with the governor's office and CPUC directives, as appropriate:

- **Outage reporting:** SCE provides customers with up-to-date information regarding outages and emergency communications and provides resources for reporting outages. SCE.com provides an interactive Outage Map for customers to determine if a customer's service territory is affected by an outage, including an outage caused by a wildfire or PSPS event. The website also provides an opportunity for customers to sign up to receive alerts, get tips to help stay safe during an outage, and connect to important resources and support programs available during an outage emergency. Please see Section 11.4.3 for more outage and community support information.
- **Support for low-income customers:** If a State of Emergency (SOE) is declared due to a natural disaster that results in a loss or degradation of electricity service, SCE implements emergency consumer protections for customers enrolled in the CARE or FERA program. For a period of one year from the SOE, income qualified customers will be protected from program verifications and recertifications and will not be removed from CARE or FERA for any reason. Customers may also reach out to SCE partner organizations like 211 to receive referral services and in certain circumstances, may receive direct assistance such as transportation, food support, or hotel accommodations.
- **Billing adjustments:** Affected customers will not receive estimated bills, and daily minimum charges are halted/adjusted.
- **Deposit waivers:** SCE does not collect deposits from residential customers. During an emergency and subsequent SOE, deposit requirements are waived for small business customers seeking to re-establish service to a new location.
- **Extended payment plans:** SCE provides customers with extended payment plans as needed.
- **Suspension of disconnection and nonpayment fees:** If a SOE is declared due to a natural disaster that results in a loss or degradation of electricity service, SCE implements emergency consumer protections to suspend service disconnection

199 SCE's 2025 AFN Plan available at https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M555/K961/555961239.PDF.

due to non-payment and waive any associated fees for a period of one year from the SOE.

- **Repair processing and timing:** SCE provides relevant information to assist with expediting rebuilding and providing up to date information about restoration timing both through the customer contact center and the web for affected customers.
- **List and description of community assistance locations and services:** SCE uses CRCs and CCVs to provide support to customers in areas experiencing a PSPS. These locations provide customers with updated outage information and resources to help during PSPS. In addition, visitors can receive water and light snacks, have access to restrooms and Wi-Fi, and can charge a small electronic device, cell phone, and certain portable medical devices.[200] SCE will continue expanding CRC locations across its service territory to ensure customers that are impacted by a PSPS, or other emergency have access to a CRC site.
- **Medical Baseline support services:** This program is for customers who are reliant on electrically operated medical or mobility equipment. This program provides customers an additional allowance of electricity per day at the lowest baseline rate, reducing the cost of operating medical equipment. Enrollment in MBL adds protections during PSPS activations and prior to de-energization through an escalated notification process. Additionally, MLB customers are also eligible for SCE's CCBB Program outlined in Section 11.5.1 below if they reside in SCE's HFRA. This program supports customers' ability to use their medical equipment in the event of an outage, including an outage propounded by a PSPS event or a wildfire.
- **Access to electrical corporation representatives:** During a disaster, SCE has a virtual resource center (SCE.com/disaster-support) and opens a dedicated hotline to address customer inquiries based on the impacts of the disaster. When applicable, SCE will provide in-person staff to county and local government assistance centers during disasters and other events to provide cohesive support to customers impacted by a disaster. During PSPS events, SCE staff are deployed to CRCs and CCVs to support customers. As needed, SCE may direct staff and resources to county and local government assistance centers during disasters and other events to provide in-person support to assist with information and consumer protections. Additionally, SCE's PSPS IMT has dedicated roles to support customer escalations. Local government leaders can contact their SCE local government representative, who then will route customer escalations through the Customer Care Branch Director and/or the Access and Functional Needs Supervisor. Access and Functional Needs Supervisors also hold daily briefing calls with impacted CBOs, who have a direct line to SCE staff to resolve customer escalations.

11.5.1 Critical Care Backup Battery Program (CCBB) (PSPS-2)

The CCBB program supports all customers enrolled in MBL that reside in a HFRA by providing a battery-powered portable backup solution to operate critical medical

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200 A list of pre-approved CRC locations can be found here: https://www.sce.com/outage-center/customer-resources-and-support/community-resource-centers.

equipment during PSPS events or other emergencies. SCE will continue to identify and offer the CCBB program to newly eligible customers, deploy backup batteries to all eligible customers who choose to participate in the program, and adjust the program outreach and strategy as needed to best serve eligible customers.

SCE plans to complete 85% of battery deliveries to eligible customers within 30 business days of program enrollment. If factors outside of SCE's control allow for faster execution, SCE will strive to complete 90% of battery deliveries to eligible customers within 45 business days of program enrollment. This level of execution is subject to customer responsiveness, availability, reschedule requests, and battery supply constraints.

11.5.2 Portable Power Station Rebate Program and Portable Generator Rebate Program (PSPS-3)

The Portable Power Station Rebate Program provides up to five $150 rebates to customers for purchasing a portable power station for their general home or small business resiliency needs. The program is available to customers residing in HFRA to assist in powering small electronics, lighting, TVs, routers and modems, and can charge devices such as cell phones, laptops, and tablets.

The Portable Generator Rebate program provides rebates to customers living in HFRA whose electrical needs extend beyond the limited power supply offered by a portable power station. Eligible customers can receive a $200 rebate toward the purchase of a generator, and for customers enrolled in CARE, FERA, or MBL, a $600 rebate toward the purchase of a generator.

SCE is evaluating enhancements to its resiliency rebate offerings and will continue to offer resiliency rebates to customers through 2028.

SCE plans to process 85% of all rebate claims within 30 business days of receipt from website vendor. If factors outside of SCE's control allow for faster execution, SCE will strive to process 90% of all rebate claims within 45 business days of receipt from website vendor. This is dependent on website related delays and subject to receiving all required customer information.

11.5.3 Disability Disaster and Access Resources (DDAR) Program

The DDAR program provides direct support to customers with AFN prior to and during PSPS and All-Hazards events to mitigate customer impacts associated with these events. Prior to an event, DDAR will help customers with AFN prepare for events by hosting emergency preparedness trainings in the community and by helping customers develop emergency resiliency plans tailored to their needs, including procuring backup power, and assisting them enroll in applicable customer care and bill support programs. During events, DDAR will assist customers with in-event battery backup needs, food vouchers, fuel vouchers to assist customers to get to a hotel and or purchase fuel for a generator as well as connecting customers to accessible transportation and accessible hotel accommodations.

11.5.4 In-Event Battery Loan Pilot

The In-Event Battery Loan Pilot supports customers with AFN who live in HFRA and use a medical device or assistive technology for independence, health, or safety. Customers temporary portable generators for critical facilities to assist with maintaining electric service for essential safety and public services emergencies.

11.5.6 PSPS 211 Service

211 Service (211) is a statewide solution that provides 24/7 live support before, during, and after a PSPS event. 211 connects customers with AFN to direct services such as shelf-stable food, hot meal deliveries, transportation, and temporary accommodations to help mitigate the impacts of PSPS or emergency related outages. 211 also connects customers with CBOs. CBOs offer social services to the community that may mitigate the impact of outages such as a paratransit agency to schedule accessible transportation or a food pantry. Outside of a PSPS activation, 211 provides outreach to customers with AFN who are living in HFRA to develop personalized safety and emergency plans. As part of the safety and emergency plan, the 211 connects customers with existing programs that can help them prepare for outages and assist them in completing applications for SCE programs such as MBL. In 2024, 211 was expanded to provide support during an all-hazards event. 211 will assist customers during an emergency by connecting callers to support services to mitigate the impacts of a disaster.

11.5.7 Customer Contact Center

SCE's Customer Contact Center provides support to customers during PSPS events by answering questions, providing information, resolving concerns, addressing emergency issues, escalating potential issues that arise, and delivering safety messaging to keep the public safe. SCE's Customer Contact Center is available to respond to customers during PSPS events and may require extended scheduled work hours for staff to ensure response times are reasonable. The Customer Contact Center also supports community outreach efforts by sending Energy Advisors to CRCs or CCVs to answer customer questions and deliver safety messaging. In addition to employees, SCE leverages contract call center vendors to handle calls and deliver safety messages.

12 ENTERPRISE SYSTEMS

In this section, the electrical corporation must provide an overview of inputs to, operation of, and support for various enterprise systems it uses for vegetation management, asset management and inspection, grid monitoring, ignition detection, weather forecasting, and risk assessment initiatives. Enterprise systems encompass structures and methods that allow the electrical corporation and its employees and/or contractors to accept, store, retrieve, and update data for the production, management, and scheduling of related work.

12.1 Targets

In this section, the electrical corporation must provide qualitative targets for each year of the three-year WMP cycle. The electrical corporation must provide at least one qualitative target for each initiative as related to implementation and improvement of its enterprise systems.

12.1.1 Qualitative Targets

The electrical corporation must provide at least one qualitative target for each relevant initiative (vegetation management, asset management and inspection, grid monitoring, ignition detection, weather forecasting, and risk assessment) in its three-year plan for implementing and improving its enterprise systems, including the following:

- *Identification of which initiative(s) and activity/activities in the WMP the electrical corporation is implementing to achieve the stated target, including Tracking IDs and the previous tracking ID used in past WMPs, if applicable.*
- *A target completion date*
- *Reference(s) to the WMP section(s) or appendix, including page numbers, where the details of the target(s) are documented and substantiated*

Table 12-1: SCE Enterprise Systems Targets

Initiative	Activity (Tracking ID #)	Previous Tracking ID (if applicable)	2026 End of Year Total / Completion Date[201]	2027 Total / Status	2028 Total / Status	Section; Page number
12 Vegetation Management Enterprise Systems	Vegetation Work Management System (VM-6)	VM-6	Continue enhancements and stabilization of Salesforce Field Service (SFS) Mobile application	Integrate CanopySense into Arbora for VM Transmission & Distribution inspections	Transfer record keeping from Fulcrum to Arbora for emergency response VM activities	12.2; p. 479
12 Asset Inspections Enterprise Systems	Inspection and Maintenance Tools (IN-8)	IN-8	Train users and roll out InspectForce software solution for distribution (ground-only) and 360 inspections (combined aerial & ground)	Integrate baseline computer vision (CV) models into 360 Inspections process to enhance inspection efficiency using InspectForce by reducing survey questions for manual data collection	Integrate expanded set of computer vision (CV) models into 360 Inspections process to further enhance efficiency of field inspection using InspectForce by reducing or avoiding the addition of new survey questions	12.2; p. 479
10.3 Grid Monitoring Systems	Distribution Open Phase Detection (DOPD) (SA-14)	N/A	See Table 10-1	See Table 10-1	See Table 10-1	See Table 10-1
10.4 Ignition Detection Systems	HD Camera Improvement (SA-18)	N/A	See Table 10-1	See Table 10-1	See Table 10-1	See Table 10-1
10.5 Weather Forecasting	Weather and Fuels Modeling (SA-3)	SA-3	See Table 10-1	See Table 10-1	See Table 10-1	See Table 10-1
12 Risk Assessment Enterprise Systems	POI Model Asset Data Refresh (RM-1)	N/A	Refresh POI model with latest asset data	Refresh POI model with latest asset data	Refresh POI model with latest asset data	12.2; p. 479

201 The completion date for all qualitative targets is December 31st for each year unless otherwise specified.

12.2 Summary of Enterprise Systems

Electrical corporations must provide a summary narrative of no more than three pages that discusses how its enterprise systems contain, account, or allow for the following:

- *Any database(s) the electrical corporation used for data storage.*
- *Internal procedures for updating the enterprise system, including database(s), any planned updates, and the ability to migrate data across systems and ensure accuracy if necessary.*
- *The electrical corporation's asset identification process.*
- *The electrical corporation's process for integrating 100% percent asset identification or its justification if not currently in place.*
- *Processes to ensure data integrity (accuracy, completeness, and quality of data), accessibility (ability of the electrical corporation to access data across formats and locations), and retention (any policies the electrical corporation for how long it stores data and how it disposes of data after any retention period).)*
- *Any QA/QC or auditing of its system.*
- *Overview of any data governance plan that the electrical corporation has in place. Highlighting any data stewardship practices.*
- *How current WMP initiatives and activities are being tracked and monitored in enterprise systems.*
- *Employee and/or contractor ability to access and interact with the data and systems for tracking work order status and scheduling.*
- *How the electrical corporation's work order and asset management systems feed into risk analysis and alternative or interim activity selection.*
- *Any changes to the electrical corporation's enterprise systems since the last Base WMP submission and a brief explanation as to why those changes were made. Include any planned improvements or updates to the enterprise systems and the timeline for implementation.*

Any database(s) the electrical corporation used for data storage.

SCE has implemented information governance across all enterprise systems including a combination of internal Information Technology (IT) and external contractor support and maintenance. This has ensured consistent access management, data integrity, and approaches to maintenance for systems used across the enterprise for reporting and analytics in support of both wildfire and non-wildfire activities. In individual cases, SCE systems may have processes and procedures tailored to their functional area or platform or be managed by external vendors, as discussed below.

Risk Assessment: SCE maintains a database in SQL of ignitions, wire-downs, underground equipment failures, and repair orders. SCE's failure analysis engineers use the risk event information to document root cause and analyze trends. Additionally, SCE's Probability of Ignition (POI) model is calibrated with data from the risk event database and stored in an enterprise SQLite repository along with Consequence Models.

Asset and Vegetation Management and Inspections: SAP is SCE's system of record for asset inventory and asset conditions. Because SCE is in the process of updating from legacy SAP systems, SCE will relocate master asset data to S4HANA from 2026 to 2028. SCE's Consolidated Geographic Information System (cGIS) provides spatial data and is the system of record for asset location data on GE Smallworld (GESW) and Map 3D. Asset records are used to refresh SCE's POI model annually.

The Salesforce platform hosts both the wildfire asset inspections (InspectForce) and vegetation management (Arbora) work management systems of record.[202] SCE is implementing InspectForce for Distribution Ground and 360 Inspections and will utilize computer vision(CV) AI/ML models to reduce survey questions within InspectForce to limit manual data collection and increase inspection efficiency (see Section 8.3.1.3 for more information about AI/ML models). SCE is also piloting integration of CanopySense, a cloud-based platform that utilizes LiDAR or imagery (e.g., satellite, orthoimagery) to determine vegetation encroachment to SCE's circuit lines, with Arbora.[203] Fulcrum continues to be used for Integrated Vegetation Management and emergency response work but SCE aims to transition record keeping to Arbora in the future.[204] SCE also uses FMP360, a vendor managed mobile field remediation solution, for the closure of work orders and notifications.

Integration of Wildfire Mitigation Data: Wildfire Safety Data Management (WiSDM) and PSPS Centralized Data Platform (CDP) are built on the cloud based Palantir Foundry platform for unified wildfire data. Since 2023, SCE has consolidated wildfire and other spatial data in WiSDM for Quarterly Data Reporting (QDR) to OEIS. SCE is further centralizing wildfire data reporting by adding non-spatial data sets to WiSDM. PSPS CDP, meanwhile, integrates situational awareness data including weather forecasts, circuit information, operational workflows from Integrated PSPS Event Management System
(iPEMS), and customer information from SCE's outage management system (OMS). PSPS CDP uses the data to inform operations, initiate customer and Liaison Notifications, and publish data on PSPS external partner portals such as sce.com and Public Safety Partner Portal (PSPP). Ezy Data was implemented by SCE in activity DG-1 to integrate unstructured data including photos, videos, LiDAR, remote sensing data[205] from inspections in the Google Cloud Platform (GCP). The system stores unstructured

202 iPads are issued to field users to perform inspections and remediations.
203 See Section 9.2.1.6 for more information about piloting CanopySense.

metadata stored in an Elastic Search database, used by inspection data visualizers GRViewer and DRTViewer.

Grid Monitoring Systems: SCE's Aspen protective relay database hosts protection device settings while eDNA and OSI PI SCADA Historians capture and store grid parameters such as voltage, current, power flow, and device status changes (e.g., Circuit Breaker Open/Close, relay actuation).[206]

Ignition Detection: SCE does not maintain any enterprise systems for ignition detection but uses High Definition camera monitoring and machine learning applications hosted and managed by the University of California at San Diego (UCSD).

Weather Forecasting: Since 2023, SCE archived weather history data in Azure cloud databases to improve in-house weather models. SCE uses 4 High Performance Computer Clusters (HPCCs) to run weather and fuel models used for weather forecasting, PSPS, emergency preparedness and response. SCE is upgrading HPCC infrastructure as it nears end of life.

Internal procedures for updating the enterprise system, including database(s), any planned updates, and the ability to migrate data across systems and ensure accuracy if necessary.

System updates are typically based on SCE needs along with availability and software provider recommendations. When system updates are available, SCE loads new code into a test environment and validates the functionality end to end with regression and user acceptance testing to ensure code functions as intended. Any bugs found are communicated to vendors to be fixed and retested. When code passes testing, it is migrated to the production environment. SCE may develop and maintain procedures specific to the use of each system.

- *The electrical corporation's asset identification process.*
- *The electrical corporation's process for integrating 100% percent asset identification or its justification if not currently in place.*

SAP is the system of record for asset data and cGIS is the system of record for geographical location of assets. Other systems reference the systems of record for asset ID and location directly or indirectly to interrelate data. Asset data is updated when a change is made to the electrical infrastructure system or when a discrepancy is found between the field and SCE's databases to ensure accuracy and completeness.

Processes to ensure data integrity (accuracy, completeness, and quality of data), accessibility (ability of the electrical corporation to access data across formats and locations), and retention (any policies the electrical corporation for how long it stores data and how it disposes of data after any retention period).)

206 For vendor-managed systems used for EFD, MADEC, and Transformer EDD see Sections 10.3.3 and 10.3.4.

SCE has a corporate data retention policy (typically 7 years for each system), programs, and procedures for data management and quality control. SAP and cGIS as the asset data systems of record are integrated with work management and operational systems to maintain a single source of truth. InspectForce and Arbora use asset-level attributes extracted from SAP when SCE uploads scope to inspection apps. In addition, cGIS receives structure, asset attribute, and FLOC data from SAP. Any condition issues that are identified during an inspection that require remediation result in the creation of a notification stored in SAP. SCE also provides user job aids and training materials for users.

Any QA/QC or auditing of its system.

Software changes and updates go through rigorous QA/QC testing to help ensure all subscribing systems and interfaces continue to function to support SCE operations once the changes are put into production. QA/QC approaches vary by system and use case. SCE has used Ezy Data and Foundry to derive data insights from remote sensing data and remediate master asset data by analyzing HD images and validating asset location.

Overview of any data governance plan that the electrical corporation has in place. Highlighting any data stewardship practices.

In addition to the corporate data retention policy referenced above, SCE maintains a system source guide, functional design specifications, technical design specifications, and a landscape diagrams in Solution Architecture Documents for enterprise systems. SCE maintains procedures for asset data updates in SAP and cGIS, documentation of patches applied, release history, record of upgrades and fixes applied to the database.

How current WMP initiatives and activities are being tracked and monitored in enterprise systems.

All numbered activities in SCE's WMP are tracked in WiSDM where progress against targets are tracked. SCE uses Foundry as a centralized data source to respond to Quarterly Data Reporting and Data Requests. In addition, location in the SCE HFRA is identified as an attribute for corresponding assets and geographic areas in cGIS and SAP, which is uploaded with inspections scope into InspectForce and Arbora.

Employee and/or contractor ability to access and interact with the data and systems for tracking work order status and scheduling.

Access to SCE enterprise systems are granted through SCE's Identity Governance & Access Management system to SCE staff and contractors depending on work function and eligibility requirements. For systems managed by vendors, SCE works with the vendor to provide SCE staff and contractors with access. Work orders in Salesforce may be accessed using iPads issued to field users for inspections.

How the electrical corporation's work order and asset management systems feed into risk analysis and alternative or interim activity selection.

Extractions of equipment failure, asset information, and weather data from SCE's risk event database, SAP, and cGIS are used to refresh SCE's POI model, assess risk, and ultimately select mitigation activities. Location specific conditions and hardening status are used to determine the appropriate mitigations and interim mitigations.[207]

Any changes to the electrical corporation's enterprise systems since the last Base WMP submission and a brief explanation as to why those changes were made. Include any planned improvements or updates to the enterprise systems and the timeline for implementation.

See discussion of changes since the 2023 Base WMP and planned for each enterprise system listed in the narrative above. For further discussion of changes to risk assessment systems, see Section 5.7. For further discussion of targets for and changes to situational awareness systems see Situational Awareness and Forecasting. In addition, SCE maintains enterprise systems for PSPS, emergency management, and outreach that are discussed in Section 11.4.1.

207 Details on SCE's risk analysis and activity selection process may be found in Section 6.1.3 Activity Selection Process and 6.2.2 Interim Activities.

13 Lessons Learned

An electrical corporation must use lessons learned to drive continual 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, PSPS or outage events, and feedback from Energy Safety and other regulators.

13.1 Description and Summary of Lessons Learned

In this section, the electric corporation must provide a brief narrative describing the key lessons learned tied to feedback from government agencies and stakeholders, collaboration efforts with other electrical corporations, areas for continued improvement, PSPS or outage events, and outcomes from previous WMP cycles.

SCE summarizes its lessons learned and progress in adopting them below:

- **Risk Assessment and Mapping:** SCE utilizes standard methodologies in alignment with those prescribed in the CPUC Risk Informed Decision-Making Framework (RDF) Proceeding (Phase I-IV). This proceeding guides the methodologies employed by SCE, PG&E, SoCal Gas, and SDG&E to describe, analyze, and assess pre and most mitigated risk scores for all utility enterprise risks. Since its 2023-2025 WMP, SCE has evaluated the impact of using mean consequence values over multiple timescales, reinforcing its existing practice of using maximum consequence values. SCE has also made continuous improvements to its models, such as incorporating fire weather days.
- **Grid Design and System Hardening:** SCE has continued to engage in working groups, benchmarking studies, and internal evaluation of targets that has validated the effectiveness of covered conductor and demonstrated an improved approach to setting future grid hardening targets.
- **Asset Management and Inspections:** SCE has found new ways to manage increasing inspections workload through risk-informed work prioritization and backlog reduction, including enhanced agency coordination and agreements to facilitate permitting and access.
- **Vegetation Management and Inspections:** SCE has adopted lessons learned from joint-IOU studies on expanded clearances to better mitigate wildfire risk. In addition, it has reviewed internal procedures since the last WMP to better package work and issue integrated vegetation management scope to contractors.
- **Grid Monitoring and Control:** As SCE deploys REFCL, TOPD, and other technologies on the grid, it has refined its protection settings and systems for better situational awareness, ignition prevention, and cost savings.
- **Situational Awareness:** SCE is iterating on its weather forecasting models with academic partners such as the University of California at Santa Barbara and San Jose State University, harnessing technology innovations in AI and the vast data it has collected from weather stations.

- **PSPS, Emergency Management, Stakeholder Cooperation and Community Engagement:** SCE has made technology, process, training and preparedness enhancements to improve outreach and standardize notifications. SCE also engaged third party evaluators, strove to evaluate how to integrate PSPS damage into decision making, and make changes to its PSPS thresholds where prudent.

The narrative must also include lessons learned from prior catastrophic wildfires ignited by the electrical corporation's facilities or equipment and findings from Energy Safety compliance audits and reports.

See Sections 4.2 and 8.4 for discussion of SCE's Fire Investigation Preliminary Analysis (FIPA) process to investigate ignitions of all sizes (catastrophic and non-catastrophic) and derive lessons learned. SCE is exploring areas for improvement such as enhancements to its vegetation management activities for secondary circuits, Transmission Enhanced System Design, and updates to asset inspections surveys.

For each lesson learned, the electrical corporation must identify the following in Table 13-1:

- *The year of the Base WMP cycle the lesson learned was identified.*
- *Category and specific source of lesson learned.*
- *Brief description of the lesson learned that informed improvement to the WMP.*
- *Brief description of the proposed improvement to the WMP and which initiative(s) or activity/activities the electrical corporation intends to add or modify.*
- *If applicable, a brief description of how the lesson learned ties to implementation of a corrective action program.*
- *Estimated timeline for implementing the proposed improvement.*
- *If applicable, reference to the documentation that describes and substantiates the need for improvement, including:*
    - *Where relevant, a hyperlinked section and page number in the appendix of the WMP.*
    - *Where relevant, the title of the report, date of report, and link to the electrical corporation web page where the report can be downloaded.*
    - *If any lessons learned were derived from quantifiable data, visual/graphical representations of these lessons learned in the supporting documentation.*

Table 13-1: SCE Lessons Learned

ID #	Year of Lesson Learned	Subject	Category and Source of Lesson Learned	Description of Lesson Learned	Proposed WMP Improvement	Timeline for Implementation	Reference
1	2023	Feedback from Energy Safety or other authoritative bodies / Internal monitoring and evaluating initiatives	ACI SCE-23B-16: Implementation of SCE's Consolidated Inspection Strategy, Use of Its Tree Risk Index, and its Satellite-Based Inspection Pilot	The adoption of a consolidated inspection strategy in 2023 and 2024 resulted in efficiency gains, fewer return visits, improved coordination with environmental review (when feasible), contractor management, work scheduling, and the bidding process. Contractors that were not assigned HTMP work prior to implementation of the consolidated inspection strategy faced challenges in onboarding and retaining qualified arborists to perform HTMP work. Also, vendors were required to adjust work assignments and separate inspections by program due to the complexity of HTMP inspections.	Modified approach to generate, package, and assign vegetation management scope by combining work orders for emergent and scheduled preventive programs. SCE now issues work orders by contractor, where each vendor can fulfill all types of work. In addition, SCE is issuing work orders by circuit for distribution instead of by grid.	Completed 2024	SCE 2026 Base WMP Appendix D: Areas for Continued Improvement) SCE-23B-16, Section 9.2 (Vegetation Management Inspections)
2	2024	Collaboration with other electrical corporations and industry experts	Vegetation Line Clearances Working Group, ACI SCE-23B-17: Continuation of Effectiveness of Enhanced Clearances Joint Study	An IOU joint study identified that greater clearance reduces the probability of outages and ignitions by a measurable amount. The effectiveness of enhanced clearance diminishes during and after windy and winter storm weather conditions, which vary in impact between Northern and Southern California.	The IOU joint study was completed in December of 2024. SCE is continuing to review the study and implement recommendations, as feasible. For more information, please see SCE 2026 Base WMP Appendix D.	Completed 2024	SCE 2026 Base WMP Appendix D: Areas for Continued Improvement) SCE-23B-17, Section 9 (Vegetation Management), Appendix F Joint IOU Study of Effectiveness of Enhanced Vegetation Clearances for Wildfire Management

ID #	Year of Lesson Learned	Subject	Category and Source of Lesson Learned	Description of Lesson Learned	Proposed WMP Improvement	Timeline for Implementation	Reference
3	2024	Feedback from Energy Safety or other authoritative bodies	ACI SCE-23B-22: Consideration of PSPS Damage in Consequence Modeling	In 2024, SCE tested a predictive, data driven PSPS windspeed threshold model with a wide variety of asset, operations, and equipment failure data such as conductor and pole damage. An enhanced methodology that would update PSPS wind speed thresholds based on the probability of a wind-caused fault/outage at the circuit segment level did not produce the expected outcome due primarily to machine learning model accuracy concerns. PSPS event damages may play an important role in operational PSPS decision making, such as windspeed de-energization thresholds.	Evaluating how to incorporate PSPS event damage information into its operational PSPS decision making, including an internal review of its PSPS threshold methodologies during the 2026-2028 WMP period.	Ongoing	SCE 2026 Base WMP Appendix D: Areas for Continued Improvement) SCE-23B-22, Section 7 (Public Safety Power Shutoff)
4	2024	Feedback from Energy Safety or other authoritative bodies	ACI SCE-25U-01: Calculating Risk Scores Using Maximum Consequence Values	At OEIS direction, SCE investigated the use of mean value consequences and determined that they would change the assignment of high consequence areas in SCE's IWMS framework, where SCE performs grid hardening and more frequent structure inspections. Use of mean consequences with 8 hour burn simulations would result in a smaller area designated as high consequence and, therefore, fewer mitigations. Use of mean consequences with 24 hour burn simulations would result in a larger area being designated as high consequence and application of mitigations.	Updated wildfire risk model to incorporate a full range of fire weather days, from which probability distributions at each location can be derived. SCE is currently considering using mean value consequences based on 24-hour simulations. SCE expects to reach a decision on this by the time it files its RAMP report in 2026.	Ongoing	SCE 2026 Base WMP Appendix D: Areas for Continued Improvement) SCE-25U-01

ID #	Year of Lesson Learned	Subject	Category and Source of Lesson Learned	Description of Lesson Learned	Proposed WMP Improvement	Timeline for Implementation	Reference
5	2024	Collaboration with other electrical corporations and industry experts	ACI SCE-25U-03: Continuation of Grid Hardening Joint Studies	Through knowledge sharing with other utilities on grid hardening implementation, SCE learned that the ability of Transmission Open Phase Detection (TOPD) to detect an open phase may be enhanced by seasonal factors such as higher loading or current transformer (CT) ratios. TOPD monitor current rather than voltage like Distribution Open Phase Detection (DOPD) applications, since transmission systems may have more than one voltage source that can operate islanded.	Continuing to refine its TOPD logic to improve detection accuracy. To date, TOPD logic is mostly accurate except for a few false positive alarms.	Ongoing	SCE 2026 Base WMP Appendix D: Areas for Continued Improvement) SCE-25U-03, Section 10.3 (Grid Monitoring Systems)
6	2024	Feedback from Energy Safety or other authoritative bodies	ACI SCE-25U-04: Consideration of Prior Actuals in Grid Hardening Targets	For its 2026-2028 WMP, SCE has set its foundational grid hardening targets—covered conductor, targeted undergrounding, and REFCL—with a new approach that is intended to better account for prior year actuals. SCE undertook a more extensive internal process to develop the specific mile values, considering that the remaining covered conductor miles typically face more challenges than the miles completed between 2019 and 2023. SCE also performed a “bottoms-up” review of scope and progress for each program, with the intention to understand executable scope and timing at a granular level and with the best information available to SCE at the time of its WMP pre-submission in late March 2025.	For its 2026-2028 WMP targets for SH-1 (Covered Conductor), SH-2 (Targeted Undergrounding), SH-17 and SH-18 (REFCL), SCE has departed from its past approach of individual year targets and instead taken a cumulative approach of miles over the three-year period while still preserving intermediate annual targets to provide sufficient accountability. This will allow for year-to-year variation while still providing the accountability of quantitative targets.	Effective with 2026-2028 WMP targets	SCE 2026 Base WMP Appendix D: Areas for Continued Improvement) SCE-25U-04, Section 8.2 (Grid Design and System Hardening), Section 10.3 (Grid Monitoring Systems)

ID #	Year of Lesson Learned	Subject	Category and Source of Lesson Learned	Description of Lesson Learned	Proposed WMP Improvement	Timeline for Implementation	Reference
7	2024	Feedback from Energy Safety or other authoritative bodies / Internal monitoring and evaluating initiatives	ACI SCE-25U-06: Transmission High Fire Risk-Informed Inspections	SCE has experienced access and environmental issues that have impacted its ability to perform certain transmission high fire risk informed (HFRI) inspections. In 2024, SCE evaluated the current challenges associated with constrained inspections and devised strategies for managing such inspections in 2025 and beyond. Some constraints may be identified prior to field inspections, while others may only become apparent upon attempting access to an SCE structure or during the inspection process itself.	Implemented measures to address the identified access issues including engagement with customers and property owners, coordination with government, pre-scheduling property access, collecting information on hazards, established escalation processes, and remediation of transmission access roads.	Ongoing	SCE 2026 Base WMP Appendix D: Areas for Continued Improvement) SCE-25U-06, Section 8.3 (Asset Inspections)
8	2024	PSPS or outage events	After-Action Reviews	Live Field Observers (LFOs) can use field wind meters as an additional data source on current wind speeds. Also, this technology more efficiently and accurately logs observation data into Survey 123, which is relayed back to IMT personnel for decision making.	1. LFOs now use Bluetooth-enabled Kestrel wind meters. This allows them to attach the kestrel to a hot stick and take wind readings higher up from the ground. 2. Continue to gather lessons learned to identify any areas for improvement in resource management in order to execute on LFOs and quickly mobilize patrol resources, particularly during holidays when resources can be constrained.	1. Completed 2024 2. Ongoing	2026 Base WMP Section 10.2 (Environmental Monitoring Systems)

ID #	Year of Lesson Learned	Subject	Category and Source of Lesson Learned	Description of Lesson Learned	Proposed WMP Improvement	Timeline for Implementation	Reference
9	2024	Internal monitoring and evaluating initiatives	Areas of Concern	In 2024, SCE implemented newly identified AOC HFRI inspections for generation assets, leading to an accelerated schedule compared to prior years that coincided with resource constraints. To address the additional scope while meeting deadlines, SCE applied extra coordination criteria for outage planning, optimized scheduling and resource allocation.	The additional AOC scope will remain, and SCE will adjust work schedules based on lessons learned to optimize resource allocation and minimize operational impacts.	Completed	2026 Base WMP Section 8.3.5 (Generation HFRI Inspections)
10	2022	Collaboration with other electrical corporations and industry experts	Covered Conductor Working Group, ACI SCE-25U-03: Continuation of Grid Hardening Joint Studies	SCE has estimated a 45-year life of covered conductor (CC) to maintain effectiveness in preventing ignitions through lab testing, third-party testing in 2022, benchmarking, and manufacturer feedback. PG&E has a large service territory with varying environmental conditions that impact equipment aging and degradation in different ways and, therefore expects a range in service life from 30 to 50 years.	SCE will continue to track and analyze ignition events and may leverage this data to refine current assumptions for estimated effectiveness.	Ongoing	2026 Base WMP Appendix D: Areas for Continued Improvement) SCE-25U-03, Section 8.2 (Grid Design and System Hardening), Appendix F Joint IOU Grid Hardening Working Group Report

ID #	Year of Lesson Learned	Subject	Category and Source of Lesson Learned	Description of Lesson Learned	Proposed WMP Improvement	Timeline for Implementation	Reference
11	2019	PSPS or outage events	Drills and Exercises	SCE continues to mature its training and exercises based on lessons learned from after action reports from exercises and real-world incidents.	Training and exercise program continually updates and improves training and exercises to incorporate changes to procedures and tools used for activations. Will conduct a PSPS Full-Scale Exercise in 2025, addressing lessons learned from the 2024 season.	Ongoing	2026 Base WMP Section 11.2 (Emergency Preparedness and Recovery Plan)
12	2022	Internal monitoring and evaluating initiatives	Feedback from Community Engagement	Received recommendation to expand marketing and promotion of wildfire preparedness meetings and refine messages and channels based on 2022 performance data.	Working on expanding outreach efforts to additional social media platforms and continuing to develop ads with relevant messaging.	Ongoing	After Action Reports and PSPS Post Event Reports; 2026 Base WMP Section 11.3 (External Collaboration and Coordination), 11.4 (Public Communication, Outreach, and Education Awareness)

ID #	Year of Lesson Learned	Subject	Category and Source of Lesson Learned	Description of Lesson Learned	Proposed WMP Improvement	Timeline for Implementation	Reference
13	2022	Feedback from Energy Safety or other authoritative bodies	Independent Third- Party Evaluation - Filsinger Audit	Opportunities remain for potential replacements on HFRA hardened circuits.	1. Continue working with Cal Fire and the Board of Forestry for unique product testing for exemption status and California Codes and Regulations updates for exemption classifications. 2. Continue opportunity replacement of fuse links. SCE has made progress in tracking opportunities to replace material by bunding with other work. 3. Made improvements to SCE standards for guidance on exempt material use and replacement and improved training for inspectors.	1. Ongoing 2. Ongoing 3. Completed 2022	Filsinger Energy Partners Report
14	2022	Feedback from Energy Safety or other authoritative bodies	Independent Third- Party Evaluation - Filsinger Audit	Restrictive permitting continues to increase wildfire risk because Vegetation Management activities to address wildfire risk occur on lands administered by State and Federal agencies.	1. Continue working with the LA Department of Regional Planning (LADRP) to prioritize and process local coastal permits. Continue ongoing regular communication with LADRP. 2. Improve efficient use of the Forest Service Master Special Use Permit (MSUP) to facilitate SCE's work by increasing external engagement with agency leadership. 3. Used Instruction Memorandum with Bureau of Land Management (BLM) to decrease agency permitting time. 4. Made progress on piloting a new Operations and Maintenance Plan with BLM that can be used more broadly within the agency. 5. Increase targeted external engagement with BLM leadership through executive stakeholder working groups; focus on our activities in or near wilderness areas. 6. Increase external engagement and communication to share priorities, wildfire risk concerns, and mitigation strategies with the California Department of Fish and Wildlife.	1. Ongoing 2. Ongoing 3. Completed 2022 4. Completed 2024 5. Ongoing 6. Ongoing 7. Ongoing	Filsinger Energy Partners Report

ID #	Year of Lesson Learned	Subject	Category and Source of Lesson Learned	Description of Lesson Learned	Proposed WMP Improvement	Timeline for Implementation	Reference
					7. Increase external engagement with Department of Water Resources (DWR) related to work permitting within their right of way. Engagement is ongoing on a monthly basis and has resulted in a dedicated DWR staff member to prioritize and process SCE encroachment permits and temporary entry permits.		
15	2022	Feedback from Energy Safety or other authoritative bodies	Independent Third- Party Evaluation - Filsinger Audit	A high volume of environmental holds could impede wildfire mitigation work.	1. Adjusted work management processes in SCE Environmental 2. Pursuing further incidental take permits for greater operational flexibility in key regions. 3. Established a Master Streambed Alteration Agreement (MSAA) for work in jurisdictional waters. 4. Benchmark with other IOUs to ascertain best practices in environmental hold processes.	1. Completed 2023 2. Yosemite Toad and Arroyo Toad completed 2022; Pacific Fisher, San Bernardino Kangaroo Rat, and Santa Catalina Island Fox ongoing 3. Completed 2025 4. Ongoing	Filsinger Energy Partners Report

ID #	Year of Lesson Learned	Subject	Category and Source of Lesson Learned	Description of Lesson Learned	Proposed WMP Improvement	Timeline for Implementation	Reference
16	2022	Feedback from Energy Safety or other authoritative bodies	Independent Third- Party Evaluation - Filsinger Audit	Clarity of written checklist for long span length and slack inspection work needed improvement.	Updated standards for long long-span criteria and evaluated long-term solutions for optimizing inspection survey.	Completed 2023	Filsinger Energy Partners Report
17	2022	Feedback from Energy Safety or other authoritative bodies	Independent Third- Party Evaluation - Filsinger Audit	A significant number of questions on the inspection form address asset inventory rather than ignition/wildfire risk reduction.	1. Identified and implemented opportunities to streamline unnecessary questions. 2. Created a feasibility report and plan for adjusting to a time- based or work-based data capture approach for asset inventory questions. 3. Investigated long term vendor, in-house, and utility co-creation approaches to optimize inspection survey completion for asset inventory, including potential use of drone pictures and AI/ML to automate survey completion.	1. Completed 2023 2. Completed 2023 3. Completed 2023	Filsinger Energy Partners Report

ID #	Year of Lesson Learned	Subject	Category and Source of Lesson Learned	Description of Lesson Learned	Proposed WMP Improvement	Timeline for Implementation	Reference
18	2022	Feedback from Energy Safety or other authoritative bodies	Independent Third- Party Evaluation - Filsinger Audit	Improvement opportunities for quality assurance and quality control (QA/QC) of equipment inspections.	SCE updated its inspection survey to confirm non-exempt status for QA/QC. SCE also implemented its process for annual refresh of QC risk ranking.	Completed 2023	Filsinger Energy Partners Report
19	2022	Feedback from Energy Safety or other authoritative bodies	Independent Third- Party Evaluation - Filsinger Audit	Opportunities may exist to integrate and improve vegetation management programs to reduce potential wildfire risk.	1. Integrated vegetation line clearing, dead and dying tree, and hazard tree management plan (HTMP) vegetation programs. SCE made progress on changes to HTMP methodology including frequency and tree risk calculation. 2. SCE is issuing vegetation management work orders by circuit for distribution and in the process of analyzing the impact of transitioning scheduling of work from grids to circuit. 3. Implemented improvements to post-work verification, including QC sampling. 4. Implemented contractual changes with vendors including training and retesting to improve pre-inspection quality 5. Implemented changes to contractor field coordination with SCE Environmental Services to improve efficiency when working in Environmentally Sensitive Areas (ESA). 6. Adjusted timeliness of vegetation constraint resolution by clarifying Priority 1 criteria in HFRA to mitigate emergency conditions and develop plans to reduce non-emergency encroachment work volume.	1. Completed 2023 2. Impact analysis 2025 3. Completed 2023 4. Completed 2023 5. Completed 2023 6. Completed 2023	Filsinger Energy Partners Report

ID #	Year of Lesson Learned	Subject	Category and Source of Lesson Learned	Description of Lesson Learned	Proposed WMP Improvement	Timeline for Implementation	Reference
20	2022	Feedback from Energy Safety or other authoritative bodies / PSPS or outage events	Independent Third- Party Evaluation - Filsinger Audit	Decision-making criteria for PSPS thresholds could be more transparent in terms of how thresholds are set and updated and how covered conductor and Priority 2 conditions inform and influence thresholds.	SCE engaged a vendor to enhance PSPS decision making criteria. A core business requirement of this engagement was to produce thorough and intuitive documentation that SCE can share with regulators, intervenors and other third parties to increase PSPS threshold transparency.	Completed 2024	Filsinger Energy Partners Report
21	2023	Collaboration with other electrical corporations and industry experts	University of California at Santa Barbara Collaboration	The University of California at Santa Barbara (UCSB) evaluated rapidly updating short-term forecasts and developed a deep learning model for locations that do not have weather station coverage.	Implemented new weather forecasting technologies evaluated and developed by academic research partner UCSB. Research in this area continues and is following trends in the field of meteorology to increase use of artificial intelligence techniques to move beyond traditional weather model approaches.	Ongoing	2026 Base WMP Section 10.5 (Weather Forecasting)

ID #	Year of Lesson Learned	Subject	Category and Source of Lesson Learned	Description of Lesson Learned	Proposed WMP Improvement	Timeline for Implementation	Reference
22	2024	Collaboration with other electrical corporations and industry experts	Risk Modeling Working Group	Wildfire risk models can be improved to establish standard weather and vegetative coverage scenarios, as well as extreme-event conditions, for design purposes and long-term contingency planning.	Updated its Fire Weather Day (FWD) selection methodology based on its 40+ year historical climatology including information regarding both the observed frequency of extreme wind and fuel conditions. FWD is used to calculate risk scores using SCE's MARS framework and to prioritize mitigations using IWMS categories. SCE also notes that the use of extreme wind scenarios further supports SCE's approach in using the potential maximum consequence values of wildfire events. SCE will continue ongoing engagement in wildfire risk modeling working group for review and validation of its methodologies.	Ongoing	2026 Base WMP Chapter 5 (Risk Methodology and Assessment) and Appendix B: Supporting Documentation for Risk Methodology and Assessment(Weather Analysis), Appendix D: Areas for Continued Improvement) SCE-25U-01
23	2023	PSPS or outage events	San Jose State University's (SJSU) Wind Profiler Project	Using LiDAR to accurately predict surface-level winds during PSPS events is not efficient in any decision making factors. Real time profiling has not provided valuable insights and has been limited by data transfer speeds.	Piloted the project through the 2023 fire season and determined this effort would not add value to the de-energization decision process during PSPS events.	Completed 2023	SCE 2026 Base WMP Chapter 10 (Situational Awareness)

ID #	Year of Lesson Learned	Subject	Category and Source of Lesson Learned	Description of Lesson Learned	Proposed WMP Improvement	Timeline for Implementation	Reference
24	2024	Internal monitoring and evaluating initiatives	Target SH-17 Rapid Earth Fault Current Limiter (REFCL), ACI SCE-25U-03: Continuation of Grid Hardening Joint Studies	The joint utilities evaluated the distribution network for applications of REFCL technology to aid with wildfire mitigation efforts. SCE identified that implementing REFCL Ground Fault Neutralizer (GFN) on 4-wire circuity could create costly system changes in converting 4-wire circuitry to 3-wire circuitry to be compatible with REFCL technology.	REFCL Grounding Conversions (GC) was added as a mitigation for 4-wire circuitry as a less costly alternative. These REFCL systems are expected to help reduce ignition events by 90 percent for single phase ground fault events. Lessons learned from earlier installations and fixes has meant greater uptime for REFCL systems as well.	Completed; Effective with 2026 Base WMP Targets	SCE 2026 Base WMP Appendix D: Areas for Continued Improvement) SCE-25U-03, Section 8.2, Table 8-1 Target SH-17 and SH-18 Rapid Earth Fault Current Limiter (REFCL), Section 10.3 (Grid Monitoring Systems)

13.2 Working Group Meetings

The electrical corporation must identify any Energy Safety-required working group meetings attended or planning to attend in the WMP submission year and provide any lessons learned that applied to its WMPs. The electrical corporation must include interactions and collaborations related to the electrical corporation's WMP submission such as identifying new technology, industry best practices, and shared lessons learned from the WMP process.

SCE regularly attends several forums for technical and programmatic planning identifying new technology, industry best practices, and shared lessons learned. Lessons learned from SCE's collaboration with working groups are identified and incorporated into Table 13-1. These forums include:

- **Risk Modeling Working Group:**[208] SCE is an active participant in OEIS-sponsored Risk Modeling Working Groups (RMWG). At the OEIS RMWG utilities can engage with other large and small utilities, public agencies, and interested stakeholders to share best practices regarding utility wildfire risk modeling activities. SCE looks forward to the next phase of these working group meetings, which will focus on developing a document outlining Utility Best Practices for Wildfire Risk Modeling. OEIS has indicated that these RMWG will continue through 2027.
- **Covered Conductor Working Group:**[209] SCE met with California IOUs through 2024 regarding the effectiveness of covered conductor. These included meetings on estimated effectiveness, recorded effectiveness, laboratory testing, benchmarking, alternatives to covered conductor, new technologies, maintenance and inspection practices, PSPS impacts, and costs.
- **Vegetation Line Clearances Working Group:**[210] SCE meets with SDG&E and PG&E to discuss line clearing data collection practices and record keeping of tree-caused risk events. PG&E, SDG&E, and SCE worked with a third-party consultant to establish the data collection standards, create the cross-utility database, and study the relationship between enhanced vegetation clearances and tree-caused risk events.
- **Wildfire Mitigation:** SCE engages and shares best practices with industry trade associations and agencies, as well as other utilities by participating in conferences and other external events. Participating in industry conferences and other forums as well as engaging with peer utilities provide regular opportunities to share best practices on topics pertaining to wildfire mitigation, including PSPS. From 2023-2025, SCE participated in the following external engagements, including but not limited to:
- Association of Edison Illuminating Companies Meeting

208 For more information see Appendix D: Areas for Continued Improvement ACI SCE-25U-01.
209 For more information see Appendix D: Areas for Continued Improvement ACI SCE-25U-03.
210 For more information see Appendix D: Areas for Continued Improvement ACI SCE-23B-17.

- California Homeowners Insurance Industry and Utility Industry Wildfire Loss Mitigation Strategies Discussion
- DistribuTECH International and Innovation Summit
- Edison Electric Institute (EEI) FERC Transmission – Annual CEO Meetings
- EEI Legal Conference
- EEI Mitigation Wildfire Risk Panel
- EEI Transmission, Distribution, Metering and Mutual Assistance Conference
- Electric Utility Consultants, Inc.'s (EUCI) "Wildfire Season Recap Summit" Conference
- EPRI Studies and Conferences related to ACIs and Working Groups
- EUCI Wildfire Mitigation Utilities Conference
- Institute of Electrical and Electronics Engineers (IEEE) Panels on Fire Mitigation & Grid Resiliency and Undergrounding
- International Code Council Annual Meeting
- International Wildfire Risk Mitigation Consortium Annual Conference
- Northern California Power Agency (NCPA) Strategic Issues Conference
- National Association of Counties (NACO) Western Interstate Region Conference
- North American Transmission Forum (NATF)
- Pacific Coast Builders Conference
- Reinsurance Association of America (RAA) Catastrophe Risk Management Conference
- Western Chapter International Society of Arboriculture
- Western Conference Public Service Commissioners
- Western Energy Institute (WEI) Wildfire Conference
- Western Electricity Coordinating Council (WECC) Summer Readiness Webinar
- (WECC) Reliability in the West

- **Collaboration with Academic Institutions:** SCE is a member of and works with several research groups to research and develop wildfire and PSPS procedures and technology. For more detail on academic partnerships, see Section 9.8. SCE continues to collaborate with:
- Cal Poly San Luis Obispo's Wildland Urban Interface Fire Institute (WUI FIRE Institute): SCE is represented on the Advisory Council and participates in Institute meetings and participates on select research projects. University collaboration is ongoing and our participation allows for Utility interests to be recommended for research that will allow for continuous improvement and additional lessons learned.
- San Jose State University's Wildfire Interdisciplinary Research Center: University collaboration is ongoing and future research will allow for continuous improvement in wildfire mitigation efforts.
- University of Colorado Boulder Vegetation Build-Up Index: SCE continues to work with the University on an algorithm that uses remote sensing observations of vegetation to determine areas of vulnerability on the landscape.
- **Fast Curve Settings (FCS):** SCE meets with California IOUs to discuss wildfire risk reduction technologies including protective device settings in order to mitigate utility equipment caused wildfire ignitions. The use of fast trip settings has been widely adopted among peer utilities, and utilities continue to look at new technologies, such as Rapid Earth Fault Current Limiter (REFCL) and Open Phase Detection, to implement into their systems.
- **Public Safety Power Shutoff (PSPS):** SCE continues to meet with SDG&E and PG&E to share lessons learned and best practices regarding PSPS planning and execution, including customer experience, community outreach and engagement, risk modeling, emergency management, and operations. This meeting increases alignment amongst California electrical corporations related and provides an opportunity to integrate the results of regular benchmarking into our PSPS processes.
- **Distribution Aerial Resources:** SCE has met with SDG&E, PG&E, Duke Energy, and Southern Company to discuss programmatic and technical aspects of distribution aerial inspections including size and scope of program, image capture and processing, and future plans.
- **Wildfire Joint-IOU Meetings:** SCE continues to meet with California IOUs to perform deep dive discussions and comparisons of many areas of the WMP. Topics generally cover mitigation strategy and implementation, regulatory developments, and knowledge sharing.
- **TUG Working Group:**[211] SCE meets with California IOUs and participates in national undergrounding-related conference and industry association meetings to share lessons learned regarding undergrounding.

211 For more information see Appendix D: Areas for Continued Improvement SCE-25U-03. Continuation of Grid Hardening Joint Studies

13.3 Discontinued Activities

The electrical corporation must provide all activities from previous WMP submissions that it is no longer implementing ("Discontinued Activities"),[212] the rationale for discontinuation, the applicable lessons learned, and a list of the new or existing activities that mitigate risk in place of the discontinued activity ("Replacement Activities"), including cross-references to the page numbers within the WMP where each replacement activity is discussed.

Table 13-2 provides the required format for this information.

SCE plans to replace transmission splice inspections with X-Ray (IN-9.b) with proactive splice shunting (SH-20) for the 2026 Base WMP. Many activities included in the 2023 Base WMP have been completed and reached a steady state, such as software development and implementation, system hardening, or planned remediations.

Activities in the 2023 Base WMP concluding prior to 2026 include:

- DG-1 WiSDM / Ezy Data
- IN-9.a Transmission Spans with LineVue
- SA-1 Weather Station Installs
- SA-10 HD Cameras
- SA-8 Fire Spread Modeling
- SH-10 Tree Attachment Remediation
- SH-15 Vertical Switches
- SH-4 Branch Line
- SH-6 Circuit Breaker Relay Hardware for Fast Curve
- SH-8 Transmission Open Phase Detection
- VM-10 LiDAR Vegetation Inspections – Transmission
- VM-3 Expanded Clearances for Generation Legacy Facilities
- VM-9 LiDAR Vegetation Inspections – Distribution

Discontinued activities are summarized in Table 13-2.

212 Discontinued activities do not include activities that the electrical corporation has completed. An activity that has been completed is not a discontinued activity.

Table 13-2: SCE Lessons Learned From Discontinued Activities

Discontinued Activity (Tracking ID)	**Rationale for Discontinuation**	**Lessons Learned**	**Replacement Activities (include page # where discussed)**
Transmission Splices with X-Ray (IN-9.b)	Instead of inspecting first, SCE will move to proactively apply a shunt to splices. See Section 8.2 on Proactive Splice Shunting.	X-ray inspections from 2022-2024 resulted in a high rate of splice shunting. See Section 8.2 on Proactive Splice Shunting.	See Table 8-1 target SH-20 Transmission Proactive Splice Shunting and Section 8.2 on Proactive Splice Shunting. p. 222.

APPENDIX A: DEFINITIONS

Unless otherwise expressly stated, the following words and terms, for the purposes of these Guidelines, have the meanings shown in this chapter.

Definition of Terms

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. (Gov. Code, § 8593.3(f)(1).)
Asset (utility)	Electric lines, equipment, or supporting hardware.
Benchmarking	A comparison between one electrical corporation's protocols, technologies used, or mitigations implemented, and other electrical corporations' similar endeavors.
Burn likelihood	The likelihood that a wildfire with an ignition point will burn at a specific location within the service territory based on a probabilistic set of weather profiles, vegetation, and topography.

Term	Definition
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).
Circuit segment	A specific portion of an electrical circuit that can be separated or disconnected from the rest of the system without affecting the operation of other parts of the network. This isolation is typically achieved using switches, circuit breakers, or other control mechanisms.
Consequence	The adverse effects from an event, considering the hazard intensity, community exposure, and local vulnerability.
Contact from 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 from vegetation likelihood of ignition	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 PSPS events. These include the following: Emergency services sector: Police stations Fire stations

Term	Definition
	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: 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 D.01-06-085)

Term	Definition
	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).
Dead fuel moisture	The moisture content of dead organic fuels, expressed as a percentage of the oven dry weight of the sample, that is controlled entirely by exposure to environmental conditions.
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].)

Term	Definition
Discussion-based exercise	Exercise used to familiarize participants with current plans, policies, agreements, and procedures or to develop new plans, policies, 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. (FEMA/UNDRR.)
Enhanced inspection	Inspection whose frequency and thoroughness exceed the requirements of a detailed inspection, particularly if driven by risk calculations.
Equipment caused 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 hazard index	A numerical rating for specific fuel types, indicating the relative probability of fires starting and spreading, and the probable

Term	Definition
	degree of resistance to control; similar to burning index, but without effects of wind speed.
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.
Fireline intensity	The rate of heat release per unit time per unit length of fire front. Numerically, it is the product of the heat yield, the quantity of fuel consumed in the fire front, and the rate of spread.
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 continuity	The degree or extent of continuous or uninterrupted distribution of fuel particles in a fuel bed thus affecting a fire's ability to sustain combustion and spread. This applies to aerial fuels as well as surface fuels.
Fuel density	Mass of fuel (vegetation) per area that could combust in a wildfire.

Term	Definition
Fuel management	Act or practice of controlling flammability and reducing resistance to control of wildland fuels through mechanical, chemical, biological, or manual means, or by fire, in support of land management objectives.
Fuel moisture content	Amount of moisture in a given mass of fuel (vegetation), measured as a percentage of its dry weight.
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.
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.

Term	Definition
Hazard tree	A tree that is, or has portions that are, dead, dying, rotten, diseased, or otherwise has a structural defect that may fail in whole or in part and damage utility facilities should it fail
High Fire Threat District (HFTD)	Areas of the state designated by the CPUC 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	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 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.
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.

Term	Definition
Ignition likelihood	The total anticipated annualized number of ignitions resulting from electrical corporation-owned assets at each location in the electrical corporation's service territory. This considers probabilistic weather conditions, type and age of equipment, and potential contact of vegetation and other objects with electrical corporation assets. This should include the use of any method used to reduce the likelihood of ignition. For example, the use of protective equipment and device settings (PEDS) to reduce the likelihood of an ignition upon an initiating event.
Incident command system (ICS)	A standardized on-scene emergency management concept specifically designed to allow its user(s) to adopt an integrated organizational structure equal to the complexity and demands of single or multiple incidents, without being hindered by jurisdictional boundaries.
Initiative activity	See mitigation activity.
Initiative construction standards	The standard specifications, special provisions, standards of practice, standard material and construction specifications, construction protocols, and construction methods that an electrical corporation applies to activities undertaken by the electrical corporation pursuant to a WMP initiative in a given compliance period.
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).

Term	Definition
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 cope 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	Undertakings 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. Encompasses mitigation categories, mitigation initiatives, and mitigation activities within the WMP

Term	Definition
Mitigation activity	A measure that contributes to or accomplishes a mitigation initiative designed to reduce the consequences and/or probability of wildfire or outage event. For example, covered conductor installation is a mitigation activity under the mitigation initiative of Grid Design and System Hardening.
Mitigation category	The highest subset in the WMP mitigation hierarchy. There are five Mitigation Categories in total: Grid Design, Operations, and Maintenance; Vegetation Management and Inspections; Situational Awareness and Forecasting; Emergency Preparedness; and Enterprise Systems. Contains mitigation initiatives and any subsequent mitigation activities.
Mitigation initiative	Efforts within a mitigation category either proposed or in process, designed to reduce the consequences and/or probability of wildfire or outage event. For example, Asset Inspection is a mitigation initiative under the mitigation category of Grid Design, Operations, and Maintenance.
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).

Term	Definition
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 an electrical corporation whenever its 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.
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 (FEs), and full-scale exercises (FSEs).
Outage program risk	The measure of reliability impacts from wildfire mitigation related outages at a given location.
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, PSPS risk	See Outage program risk.

Term	Definition
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.
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) one-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.

Term	Definition
Protective equipment and device settings (PEDS)	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” (EPSS).
PEDS outage consequence	The total anticipated adverse effects from an outage occurring while increased sensitivity settings on a protective device are enabled at a specific location, including reliability and associated safety impacts.
PEDS outage exposure potential	The potential physical, social, or economic impact of an outage occurring when PEDS are enabled on people, property, critical infrastructure, livelihoods, health, local economies, and other high-value assets.
PEDS outage likelihood	The likelihood of an outage occurring while increased sensitivity settings on a protective device are enabled at a specific location given a probabilistic set of environmental conditions.
PEDS outage risk	The total expected annualized impacts from PEDS enablement at a specific location.
PEDS outage vulnerability	The susceptibility of people or a community to adverse effects of an outage occurring when PEDS are enabled, including all characteristics that influence their capacity to anticipate, cope with, resist, and recover from the related adverse effects (e.g., high AFN population, poor energy resiliency, low socioeconomics).
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.

Term	Definition
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 an electrical corporation requiring a PSPS given a probabilistic set of environmental conditions.
PSPS risk	The total expected annualized impacts from PSPS at a specific location. This considers two factors: (1) the likelihood a PSPS will be required due to environmental conditions exceeding design conditions, and (2) the potential consequences of the PSPS for each affected community, considering exposure potential and vulnerability.
PSPS vulnerability	The susceptibility of people or a community to adverse effects of a PSPS event, including all characteristics that influence their capacity to anticipate, cope with, resist, and recover from the adverse effects of a PSPS event (e.g., high AFN population, poor energy resiliency, low socioeconomics).
Public safety partners	First/emergency responders at the local, state, and federal levels; water, wastewater, and communication service providers; community choice aggregators (CCAs); affected publicly owned electrical corporations/electrical cooperatives; tribal governments; Energy Safety; the Commission; the California Office of Emergency Services; and CAL FIRE.
Qualitative target	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.

Term	Definition
Quantitative 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 data submissions and WMP Updates.
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. (ISO 31000:2009.)

Term	Definition
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 • 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 Public Utilities 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 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).
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.)

Term	Definition
Situational Awareness	An on-going process of gathering information by observation and by communication with others. This information is integrated to create an individual's perception of a given situation.
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.
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.
Trees with strike potential	Trees that could either, in whole or in part, “fall in” to a power line or have portions 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.

Term	Definition
Utility-related ignition	An event that meets the criteria for a reportable event subject to fire-related reporting requirements.
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)	The assessment, intervention, and management of vegetation, including pruning and removal of trees and other vegetation around electrical infrastructure for safety, reliability, and risk reduction.
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.
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.

Term	Definition
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 hazard intensity	The potential intensity of a wildfire at a specific location within the service territory given a probabilistic set of weather profiles, vegetation, and topography.
Wildfire likelihood	The total anticipated annualized number of fires reaching each spatial location resulting from utility-related ignitions at each location in the electrical corporation service territory. This considers the ignition likelihood and the likelihood that an ignition will transition into a wildfire based on the probabilistic weather conditions in the area.
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	The total expected annualized impacts from ignitions at a specific location. This considers the likelihood that an ignition will occur, the likelihood the ignition will transition into a wildfire, and the potential consequences—considering hazard intensity, exposure potential, and vulnerability—the wildfire will have for each community it reaches.

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

Definitions of Initiatives by Category

Category	Section #	Initiative	Definition
Risk Methodology and Assessment	5	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	6	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	8.2	Grid Design and System Hardening	Strengthening of distribution, transmission, and substation infrastructure to reduce the risk of utility-related ignitions resulting in catastrophic wildfires.
Grid Design, Operations, and Maintenance	8.3	Asset Inspections	Inspections of overhead electric transmission lines, equipment, and right-of-way.
Grid Design, Operations, and Maintenance	8.4	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	8.5	Quality Assurance and 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

Category	Section #	Initiative	Definition
			decision-making and related integrated workforce management processes.
Grid Design, Operations, and Maintenance	8.6	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	8.7	Grid Operations and Procedures	Operations and procedures to reduce across the electrical corporation's system to reduce wildfire risk.
Grid Design, Operations, and Maintenance	8.8	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 Inspections	9.2	Vegetation Management 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 Inspections	9.3	Pruning and Removal	Pruning, removal, and other vegetation management activities that are performed as a result of inspections.

Category	Section #	Initiative	Definition
Vegetation Management and Inspections	9.4	Pole Clearing	Plan and execution of vegetation removal around poles per Public Resources Code section 4292 and outside the requirements of Public Resources Code section 4292 (e.g., pole clearing performed outside of the State Responsibility Area).
Vegetation Management and Inspections	9.5	Wood and Slash Management	Actions taken to manage all downed wood and "slash" generated from vegetation management activities.
Vegetation Management and Inspections	9.6	Defensible Space	Actions taken to reduce ignition probability and wildfire consequence due to contact with substation equipment.
Vegetation Management and Inspections	9.7	Integrated Vegetation Management	Actions taken in accordance with Integrated Vegetation Management principles that are not covered by another initiative.
Vegetation Management and Inspections	9.8	Partnerships	Collaboration of resources, expertise, and efforts to accomplish agreed upon objectives related to wildfire risk reduction achieved through vegetation management.
Vegetation Management and Inspections	9.9	Activities Based on Weather Conditions	Actions taken in accordance with weather condition forecasts that indicate an elevated fire threat in terms of ignition probability and wildfire potential.

Category	Section #	Initiative	Definition
Vegetation Management and Inspections	9.10	Post-Fire Service Restoration	Actions taken during post-fire restoration 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.
Vegetation Management and Inspections	9.11	Quality Assurance and 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 Inspections	9.12	Work Orders	Actions taken to manage the electrical corporation's open work orders resulting from inspections that prescribe vegetation management activities.
Vegetation Management and Inspections	9.13	Workforce Planning	Programs to ensure that the electrical corporation has qualified personnel and to ensure that both employees and contractors tasked with vegetation management responsibilities are adequately trained to perform relevant work.

Category	Section #	Initiative	Definition
Situational Awareness and Forecasting	10.2	Environmental Monitoring Systems	Development and deployment of systems which measure environmental characteristics, such as fuel moisture, air temperature, and velocity.
Situational Awareness and Forecasting	10.3	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	10.4	Ignition Detection Systems	Development and deployment of systems which discover or identify the presence or existence of an ignition, such as cameras.
Situational Awareness and Forecasting	10.5	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	10.6	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.

Category	Section #	Initiative	Definition
Emergency Preparedness, Collaboration and Public Awareness	11.2	Emergency Preparedness and Recovery 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, Collaboration and Public Awareness	11.3	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. • 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.
Emergency Preparedness, Collaboration and Public Awareness	11.4	Public Communication, Outreach, and Education Awareness	• 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

Category	Section #	Initiative	Definition
			restoration, as required by Public Utilities Code section 768.6. • 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. • Actions taken understand, evaluate, design, and implement wildfire and PSPS risk mitigation strategies, policies, and procedures specific to access and functional needs customers.
Emergency Preparedness, Collaboration and Public Awareness	11.5	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.
Enterprise Systems	12	Enterprise Systems Development	Structures and methods that allow the electrical corporation and its employees and/or contractors to accept, store, retrieve, and update data for the production, management, and scheduling of related work.

Definitions of Activities by Initiative

Initiative	Section #	Activity	Definition
Grid Design and System Hardening	8.2.1	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 (12kV/in. 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.

Initiative	Section #	Activity	Definition
Grid Design and System Hardening	8.2.2	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 and System Hardening	8.2.3	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 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.
Grid Design and System Hardening	8.2.4	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 65kV).
Grid Design and System Hardening	8.2.5	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 and System Hardening	8.2.6	Emerging grid hardening technology installations and pilots	Development, deployment, and piloting of novel grid hardening technology.
Grid Design and System Hardening	8.2.7	Microgrids	Development and deployment of microgrids that may reduce the risk of ignition, risk from PSPS, and wildfire consequence. “Microgrid” is

Initiative	Section #	Activity	Definition
			defined by Public Utilities Code section 8370(d).
Grid Design and System Hardening	8.2.8	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 and System Hardening	8.2.9	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.
Grid Design and System Hardening	8.2.10	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 and System Hardening	8.2.11	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 and System Hardening	8.2.12	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.

Initiative	Section #	Activity	Definition
Grid Operations and Procedures	8.7.1	Equipment Settings to Reduce Wildfire Risk	The electrical corporation's procedures for adjusting the sensitivity of grid elements to reduce wildfire risk.
Grid Operations and Procedures	8.7.2	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.
Grid Operations and Procedures	8.7.3	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.

Appendix B: Supporting Documentation for Risk Methodology and Assessment

Note: As part of its WMP, the electrical corporation is required to provide the "Summary Documentation" as defined by this appendix. For all other requirements in this appendix, the electrical corporation must be readily able to provide the defined documentation in response to a data request by Energy Safety or designated stakeholders.

The risk modeling and assessment in the main body of these Guidelines and electrical corporation's WMP are focused on providing a streamlined overview of the electrical corporation risk framework and key findings from the assessment necessary to understand the wildfire mitigation strategy presented in Chapter III, Section 6.

The focus of this appendix is to provide additional information pertaining to the risk modeling approach used by the electrical corporation. This includes the following:

- *Additional detail on model calculations supporting the calculation of risk and risk components*
- *Additional detail on the calculation of risk and risk components*
- *More detailed presentation of the risk findings*

The following sections establish the reporting requirements for the approaches used by the electrical corporation to calculate each risk and risk component. These have been synthesized and adapted from guidance documents on model quality assurance developed by many agencies, with a focus on guidance related to machine learning, artificial intelligence, and fire science and engineering. These guidance documents include those from the Institute of Electrical and Electronics Engineers (IEEE), the Society of Fire Protection Engineers (SFPE), the American Society for Testing and Materials (ASTM International), the U.S. Nuclear Regulatory Commission (NRC), the Electric Power Research Institute (EPRI), the National Institute of Standards and Technology (NIST), and the International Organization for Standardization (ISO).

Model Inventory

The electrical corporation must provide a model inventory listing all models and associated inputs and outputs used in the development of the WMP. The model inventory should follow the below format:

Table B-01: SCE Model Inventory

Model Name	*Model Description*	*Inputs*	*Outputs*
Overhead Conductor Equipment/Facility Failure (EFF)	Model predicts outages with potential to cause sparks where the leading factor is equipment failure	GIS Conductor Data, Conductor Physical Characteristics, Vegetation Inspection/Proximity, Aggregated Climatology, Short Circuit Duty, Current Flux Density	Probability of Failure
Overhead Conductor Contact with Foreign Object (CFO)	Model predicts outages with potential to cause sparks where the leading factor is contact with a foreign object	GIS Conductor Data, Conductor Physical Characteristics, Vegetation Inspection/Proximity, Aggregated Climatology, Fatality Analysis Reporting System	6 Way Multi Label (Vegetation, Animal, Vehicle Hit, Balloon, Other, Unknown) Probability of Failure
Transformer Failure Sub-Model	Model predicts transformer failures as indicated by deterioration, damage, and failure SAP replacement codes	Transformer Inventory Data, Aggregated Climatology, Short Circuit Duty, Meter Usage	Probability of Failure
Switch Failure Sub-Model	Model predicts switch failures as indicated by deterioration, damage, and failure SAP replacement codes and inspection notifications	Switch Inventory Data, Switching Operations, Aggregated Climatology, Short Circuit Duty	Probability of Failure
Capacitor Notification Sub-Model	Model predicts capacitor failures as indicated by	Capacitor Inventory Data, Aggregated Climatology,	Probability of Failure

Model Name	*Model Description*	*Inputs*	*Outputs*
	deterioration, damage, and failure inspection notifications	Capacitor Health Data (automated devices), Historical Circuit Reliability	

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 B-1. An example is provided below.*
- ***High-level calculation procedure schematic** in the format shown in Figure 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.*
  - *Concise description and timeline of planned changes to the calculation procedure over the triennial WMP cycle.*

Figure B-1. Example Bow Tie Schematic

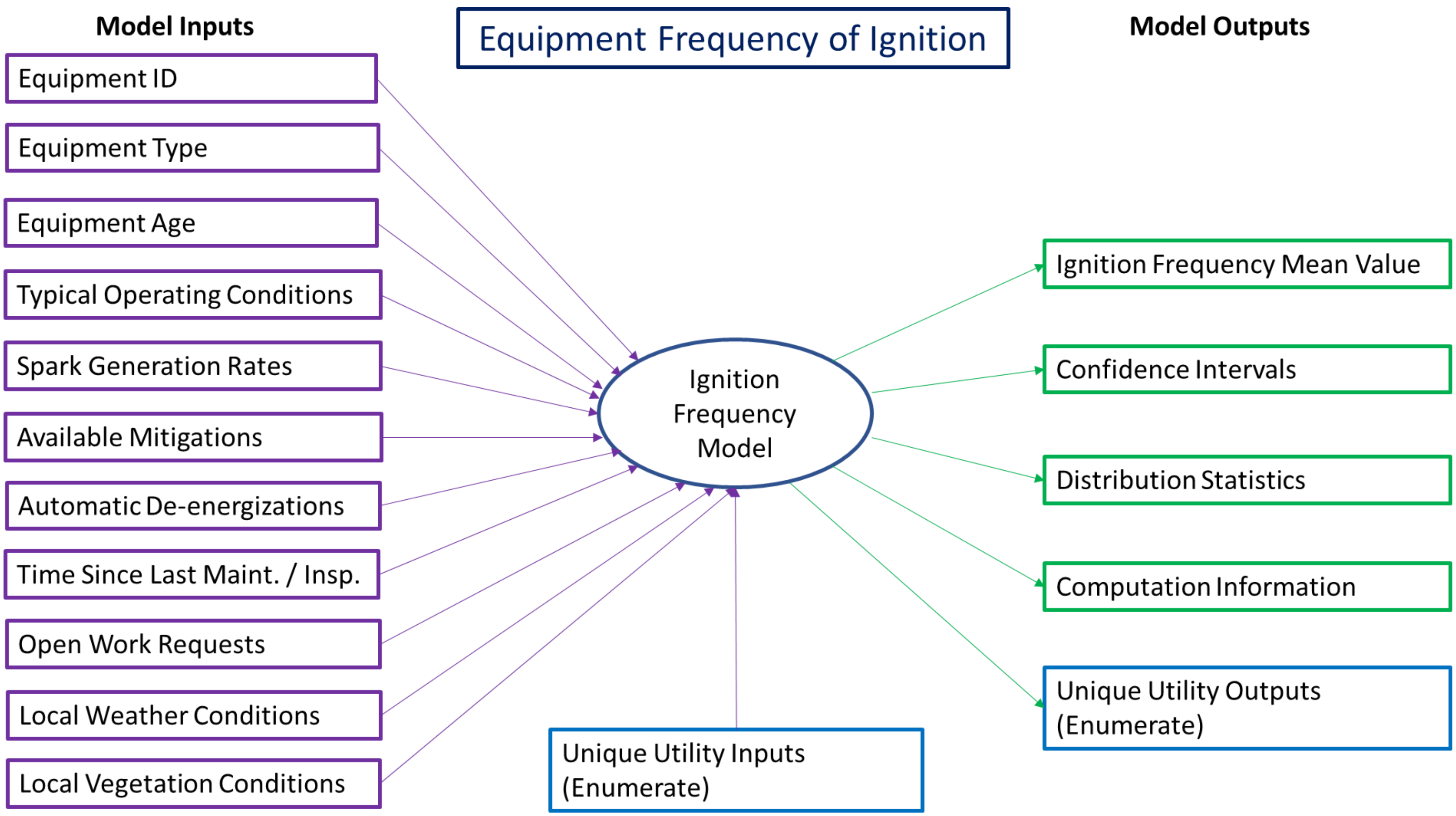
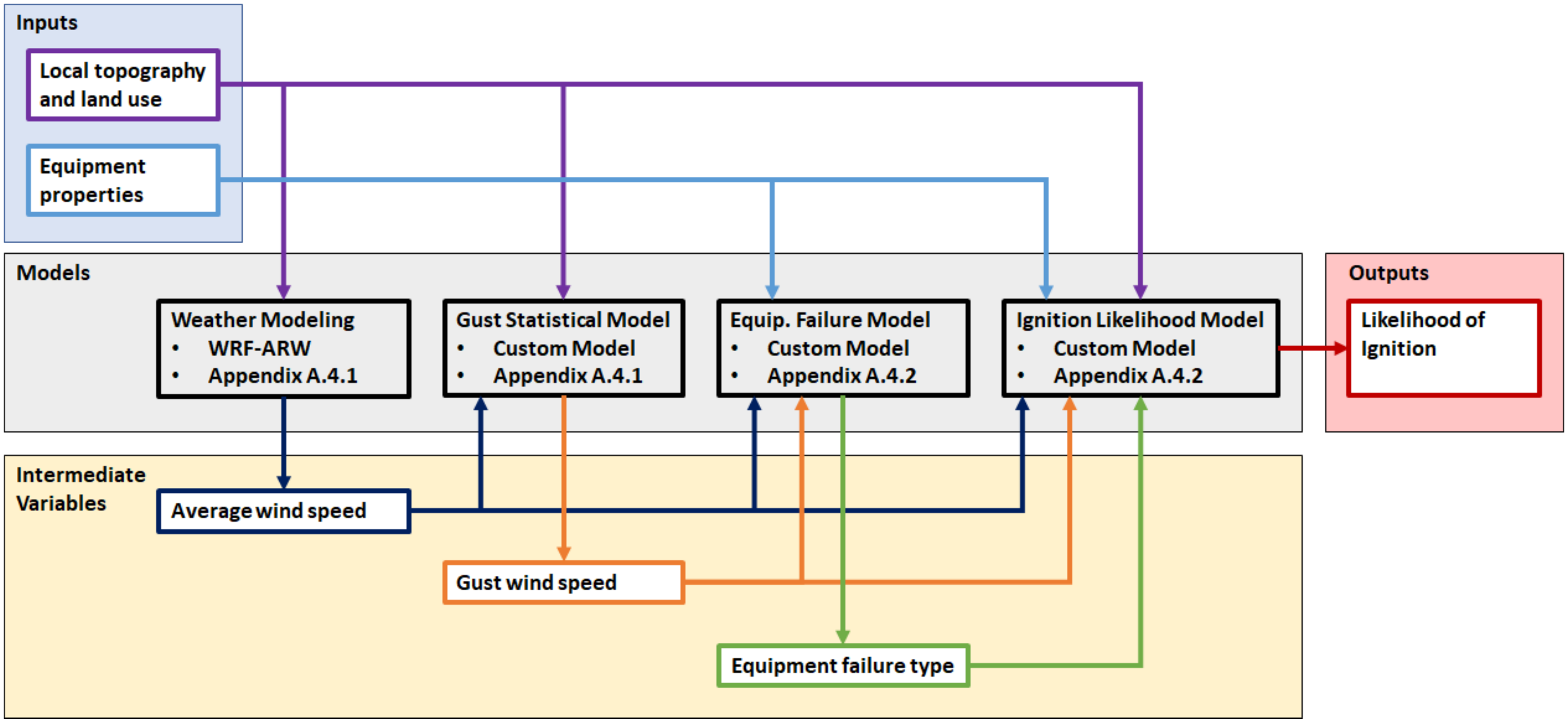


Figure B-2. Example Calculation



Schematic

R1: Overall Utility Risk

Figure SCE B-01: SCE's Overall Utility Risk Bow Tie Schematic

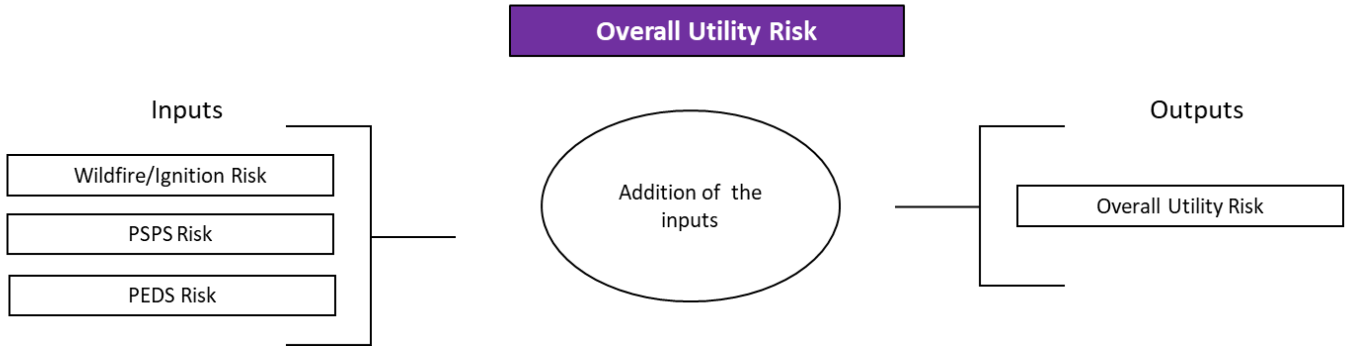
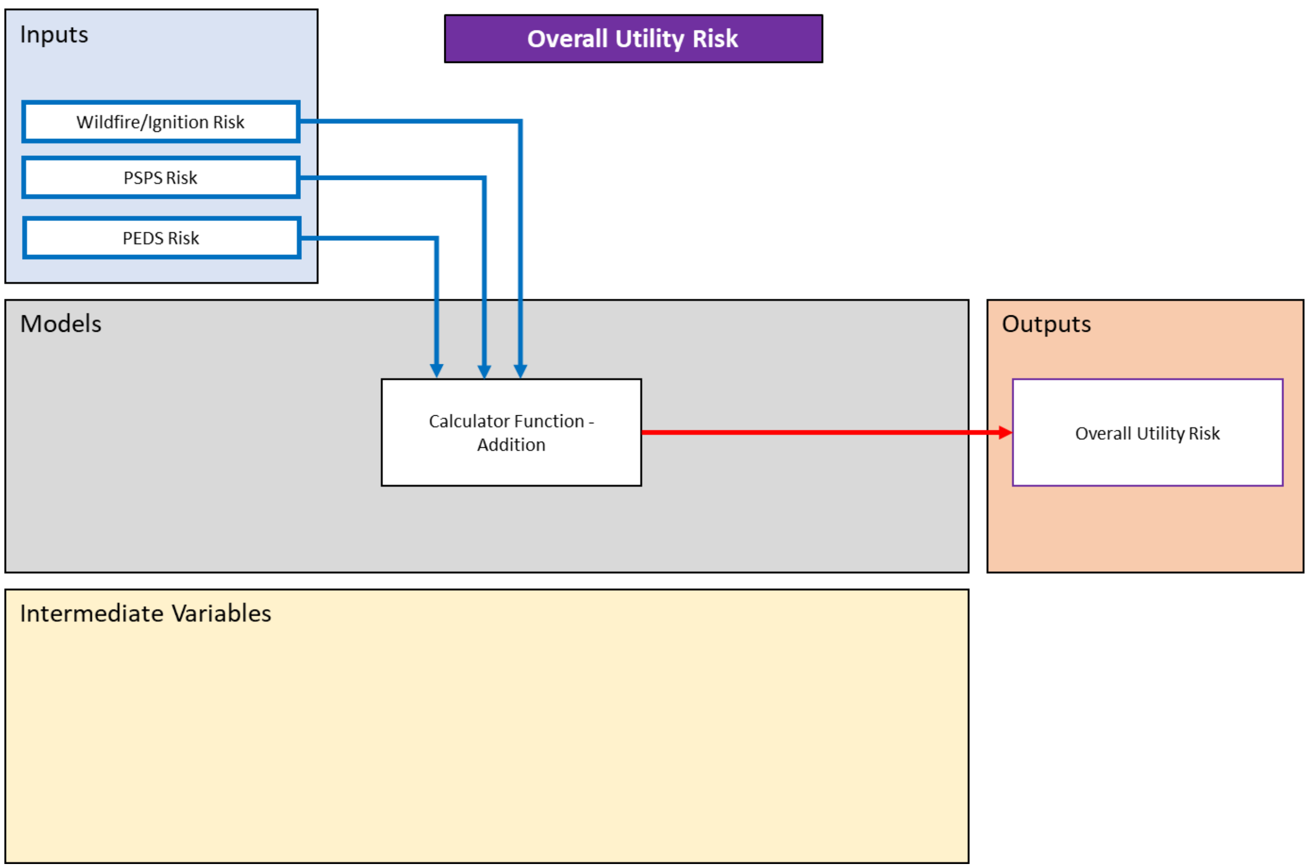


Figure SCE B-02: SCE's Overall Utility Risk Calculation Procedure Schematic



Purpose of the calculation/model

Overall Utility Risk calculates the overall risk, based on its sub-components: Wildfire/Ignition, PSPS, and PEDS Risk.

Assumptions and limitations

The risk calculation is based on assumptions and limitations from more granular sub-components (e.g., Likelihood of Ignition, Wildfire Consequence, etc.).

Description of the calculation procedure shown in the bow tie and high-level schematics

Overall Utility Risk is a summation of the Wildfire, PSPS, and PEDS Risk components.

Description of how outputs will be characterized and presented (e.g., visualization) to decision makers

Overall Utility Risk can be broken down into its components (Wildfire/Ignition, PSPS, and PEDS Risk) and shown in aggregate or individually, depending on the purpose of the presentation.

Concise description and timeline of planned changes to the calculation procedure over the triennial WMP cycle

Overall Utility Risk is a composite of all the individual sub-components. Please refer to the individual sub-components for description and timeline of key improvements.

R2: Wildfire Risk

Figure SCE B-03: SCE's Wildfire Risk Bow Tie Schematic

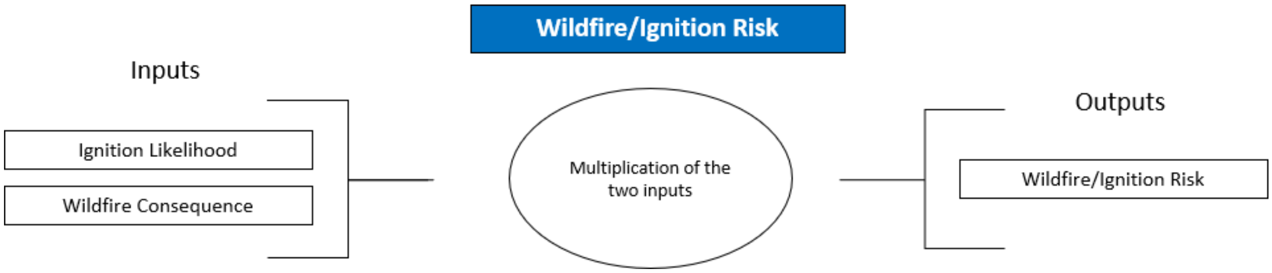
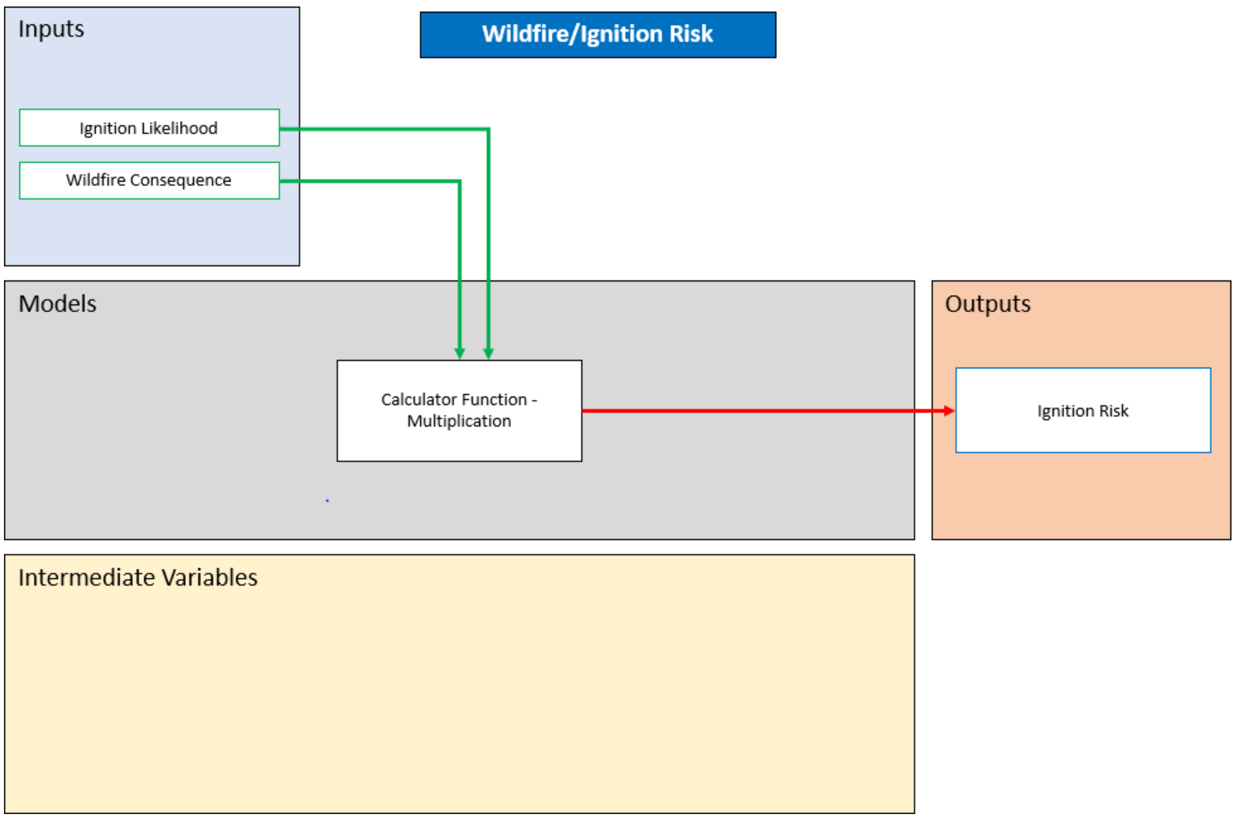


Figure SCE B-04: SCE's Wildfire Risk Calculation Procedure Schematic



Purpose of the calculation/model

SCE considers Ignition Risk synonymous with Wildfire Risk, which is based on its two sub-components, Ignition Likelihood (IRC2) and Wildfire Consequence (IRC3).

Assumptions and limitations

The risk calculation is based on assumptions and limitations from more granular sub-components (e.g., Likelihood of Ignition, Wildfire Consequence, etc.)

Description of the calculation procedure shown in the bow tie and high-level schematics

Ignition or Wildfire Risk is a product of the Ignition Likelihood (IRC2) and Wildfire Consequence (IRC3).

Description of how outputs will be characterized and presented (e.g., visualization) to decision makers

Ignition or Wildfire Risk can be broken down into its two components (Ignition Likelihood (IRC2) and Wildfire Consequence (IRC3) and can be further broken down into the subcomponents (e.g. Equipment Failure or Contact from Object Likelihood), depending on the purpose of the presentation.

Concise description and timeline of planned changes to the calculation procedure over the triennial WMP cycle

In addition to the improvements listed in Section 5.7, SCE will review feedback from the Wildfire Risk Modeling Working group and other stakeholder forums to assess key improvements or changes.

R3: Outage Program Risk

Figure SCE B-05: SCE's Outage Program Risk Bow Tie Schematic

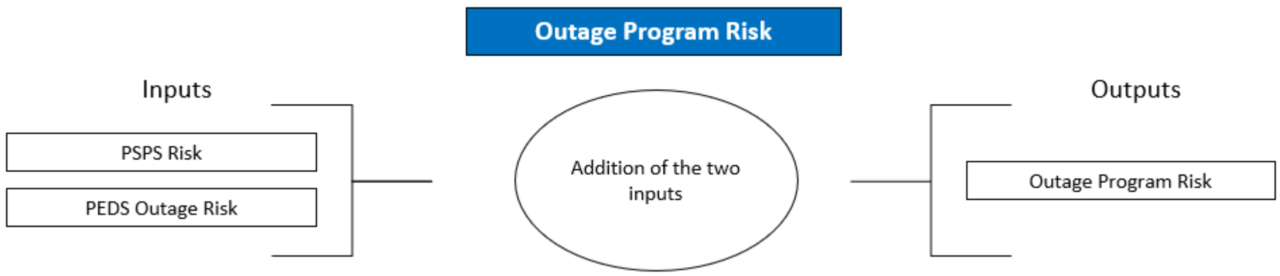
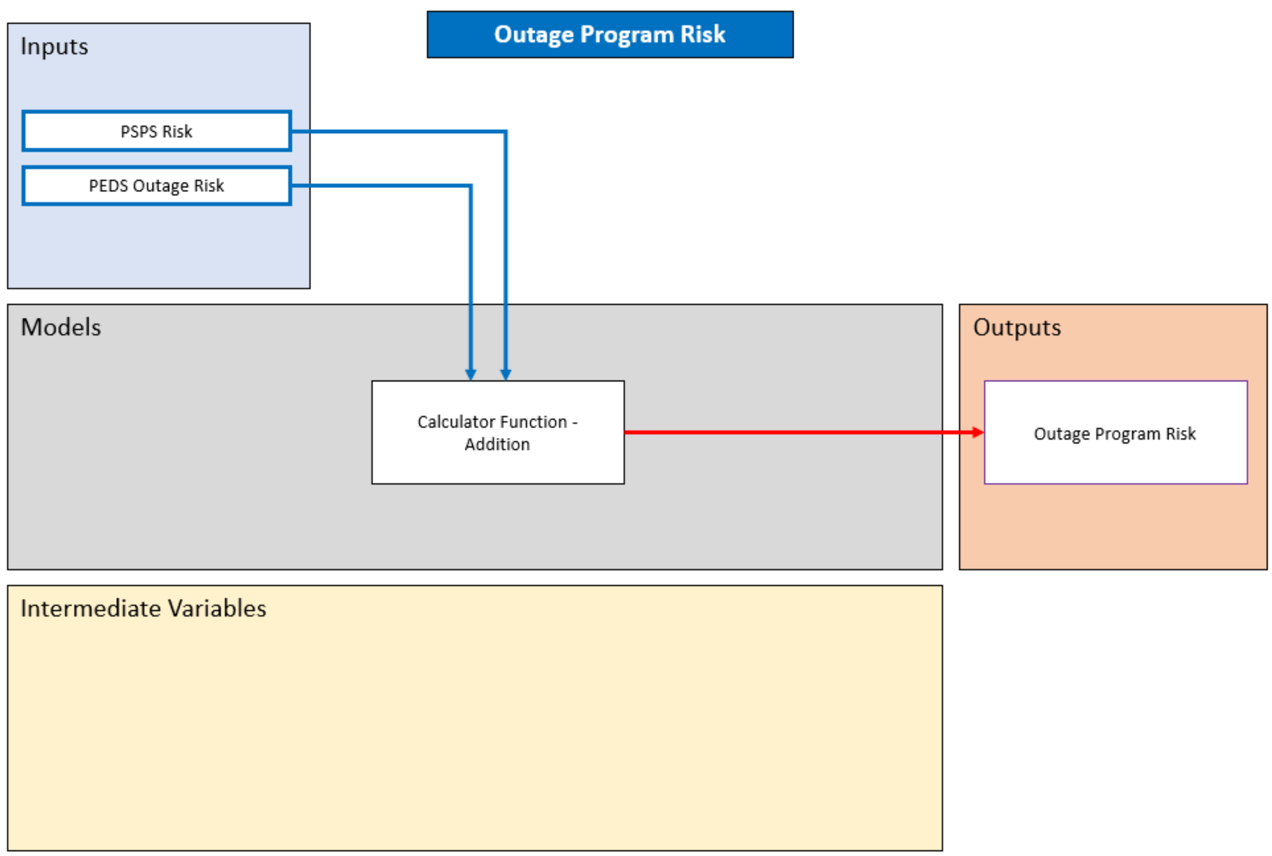


Figure SCE B-06: SCE's Outage Program Risk Calculation Procedure Schematic



Purpose of the calculation/model.

Outage program risk measures the reliability impacts from wildfire mitigation related outages at a given location.

Assumptions and limitations.

The risk calculation is based on assumptions and limitations from more granular sub-components.

- For PSPS Risk: PSPS Likelihood and PSPS Consequence
- For PEDS Outage Risk: PEDS Outage Likelihood and PEDS Outage Consequence

Description of the calculation procedure shown in the bow tie and high-level schematics.

Outage Program Risk is calculated as the sum of PSPS risk (IRC4) and PEDS Outage risk (IRC7).

Description of how outputs will be characterized and presented (e.g., visualization) to decision makers.

Outage Program Risk components (PSPS Risk and PEDS Outage Risk) can be shown individually or shown as a single risk score per circuit, depending on the purpose of the presentation.

Concise description and timeline of planned changes to the calculation procedure over the triennial WMP cycle.

In addition to the improvements listed in Section 5.7, SCE will review feedback from the Wildfire Risk Modeling Working group and other stakeholder forums to assess key improvements or changes.

IRC1: Wildfire Likelihood

SCE considers Wildfire likelihood to be synonymous with Ignition Likelihood (IRC2).

IRC2: Ignition Likelihood

Figure SCE B-07: SCE's Ignition Likelihood Bow Tie Schematic

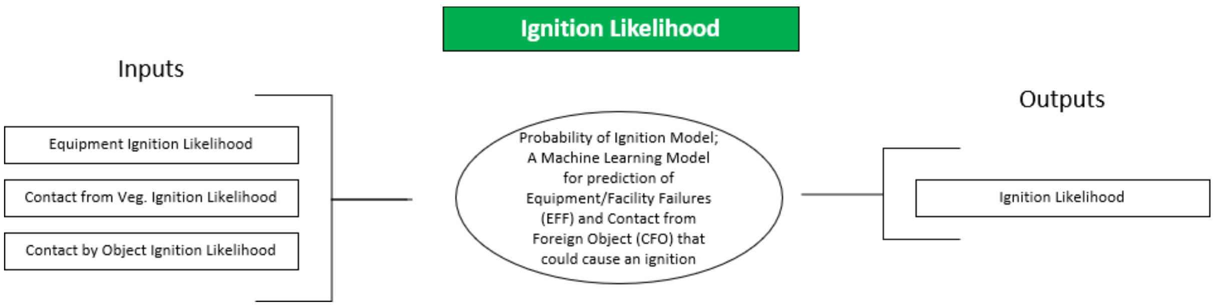
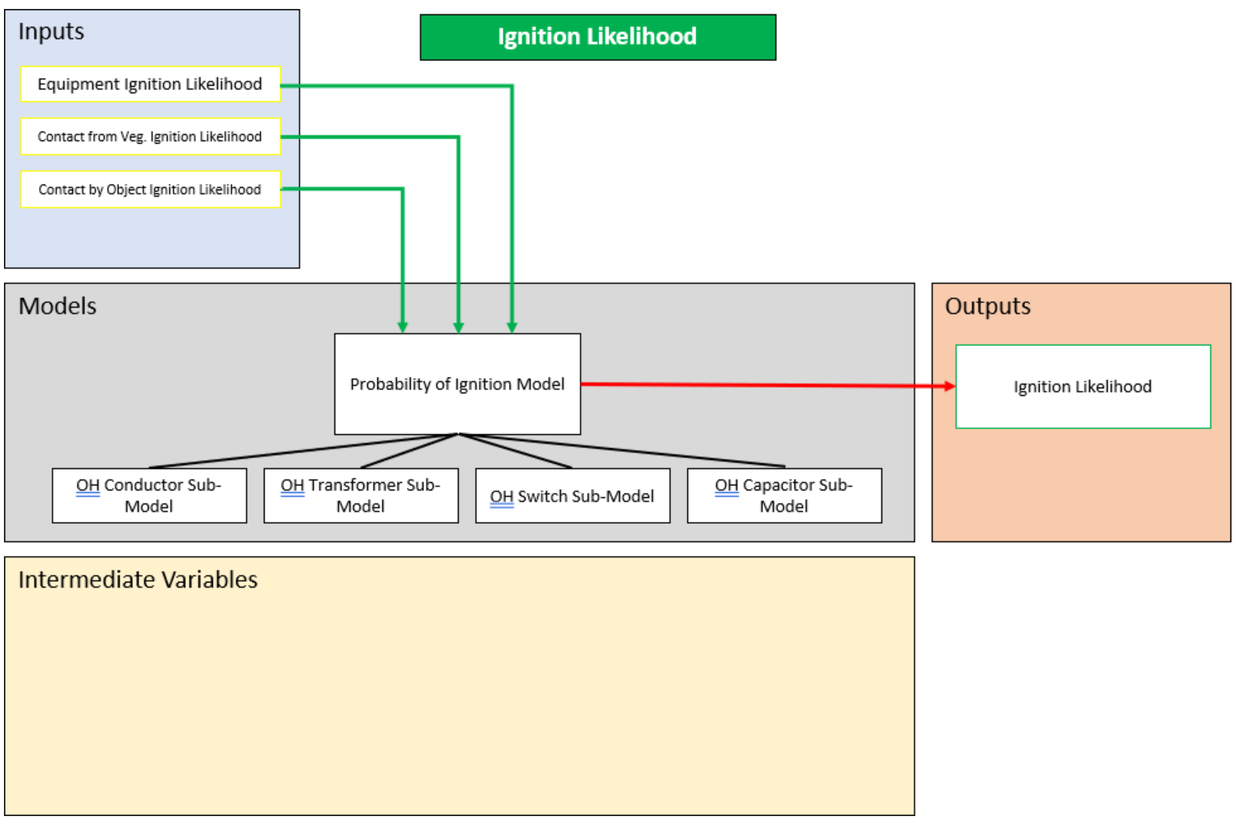


Figure SCE B-08: SCE's Ignition Likelihood Calculation Procedure Schematic



Purpose of the calculation/model

SCE considers Ignition Likelihood (IRC2) to be synonymous with Probability of Ignition (POI), which is based on inputs of the sub-component likelihood models: Equipment Caused Ignition Likelihood (FRC1), Contact from Vegetation Likelihood of Ignition (FRC2), and Contact from Object Likelihood of Ignition (FRC3).

Assumptions and limitations

The probability of ignition is a probabilistic assessment of each asset's pre-mitigated ignition likelihood prior to mitigation deployment. SCE does not differentiate between Ignition Likelihood and Wildfire Likelihood.

Description of the calculation procedure shown in the bow tie and high-level schematics

POI is the sum of the ignition component probabilities at that location (i.e., Equipment Caused Ignition Likelihood (FRC1), Contact from Vegetation Likelihood of Ignition (FRC2), and Contact from Object Ignition Likelihood (FRC3)).

Description of how outputs will be characterized and presented (e.g., visualization) to decision makers

Ignition Likelihood can be broken down into its components (i.e., Equipment Caused Ignition Likelihood (FRC1), Contact from Vegetation Likelihood of Ignition (FRC2), and Contact from Object Ignition Likelihood (FRC3) and can be further broken down into the sub-drivers (e.g. EFF - Transformers, CFO – Balloon, CFO – Animal, CFO – Vehicles, etc.), depending on the purpose of the presentation.

Concise description and timeline of planned changes to the calculation procedure over the triennial WMP cycle.

In addition to the improvements listed in Section 5.7, SCE will review feedback from the Wildfire Risk Modeling Working group and other stakeholder forums to assess key improvements or changes.

IRC3: Wildfire Consequence

Figure SCE B-09: SCE's Wildfire Consequence Bow Tie Schematic

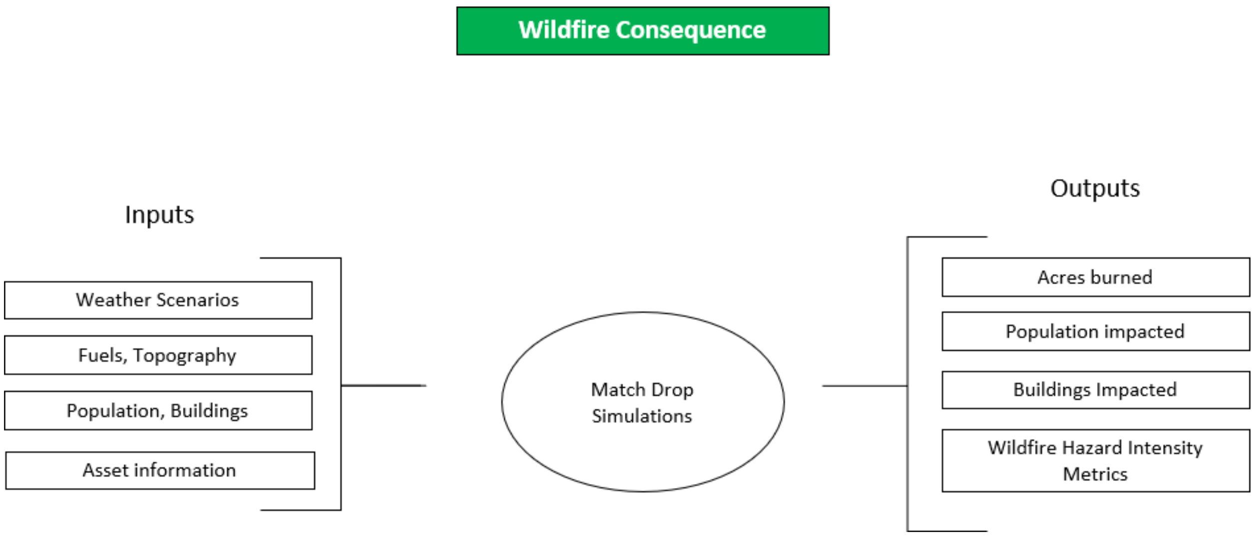
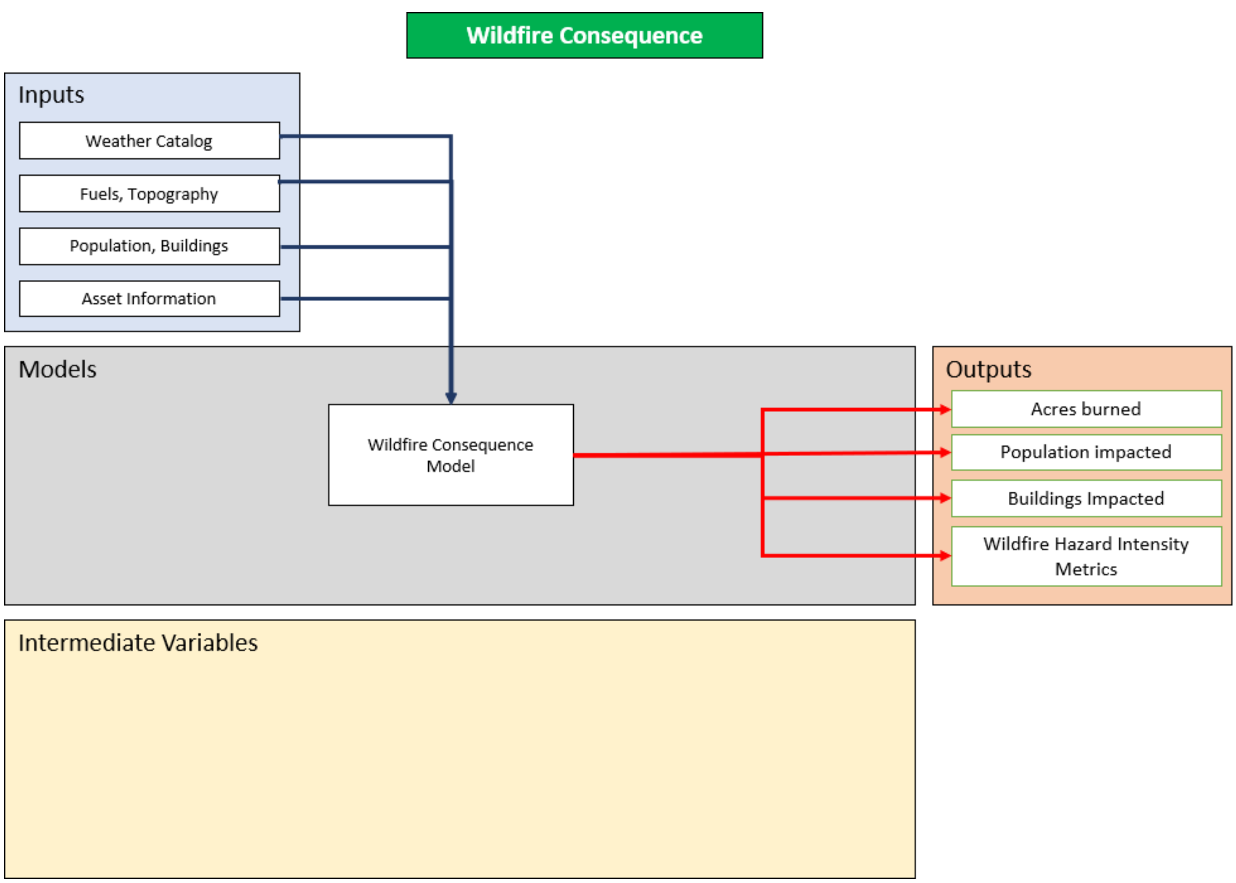


Figure SCE B-10: SCE's Wildfire Consequence Calculation Procedure Schematic



Purpose of the calculation/model

Wildfire Consequence is used, in conjunction with Wildfire Vulnerability, to assess the impact of potential consequences associated with an ignition event in proximity to overhead assets.

Assumptions and limitations

SCE runs deterministic simulations based on truncated 8- and 24-hour, unsuppressed burn times across all relevant Fire Weather Days (FWD) relevant to each Fire Climate Zone (FCZ) for all ignition locations. These simulations are representative of a deterministic maximum first burning period. These simulations are intended to provide a relative comparison of the wildfire risk across the landscape in proximity to overhead utility assets.

Description of the calculation procedure shown in the bow tie and high-level schematics

SCE estimates Wildfire Consequence (e.g., acres burned, structures impacted, population impacted) and their associated safety and financial impacts for a given set of deterministic match drop simulations for all overhead assets in SCE's service territory, as well as in adjacent locales across all relevant Fire Weather Days (FWD) relevant to each Fire Climate Zone (FCZ) for all ignition locations using a 2035 fuel projection.

Description of how outputs will be characterized and presented (e.g., visualization) to decision makers

SCE utilizes these natural unit consequence to estimate risk reduction using SCE's MARS Risk Framework (see Section 5.2.1.1), and to categorize risk within the context of SCE's IWMS Risk Framework (see Section 5.2.1.2).

In the IWMS Risk Framework, SCE categorizes simulated wildfires based on three wildfire outcomes:

- Significant Fires are simulated fires that at 8 hours after ignition, burned more than 10,000 acres or had at least one fatality or had at least 50 structures impacted;
- Destructive Fires are simulated fires that, at 8 hours after ignition, burned between 300 acres and 10,000 acres with zero fatalities and/or had fewer than 50 structures impacted;
- Small Fires are simulated fires that, at 8 hours after ignition, burned less than 300 acres with zero fatalities and no structures impacted.

Please see the description of the IWMS methodology in Section 5.2.1.2 for additional factors considered such as egress and burn-in buffer.

Concise description and timeline of planned changes to the calculation procedure over the triennial WMP cycle.

In addition to the improvements listed in Section 5.7, SCE will review feedback from the Wildfire Risk Modeling Working group and other stakeholder forums to assess key improvements or changes.

IRC4: PSPS Risk

Figure SCE B-11: SCE's PSPS Risk Bow Tie Schematic

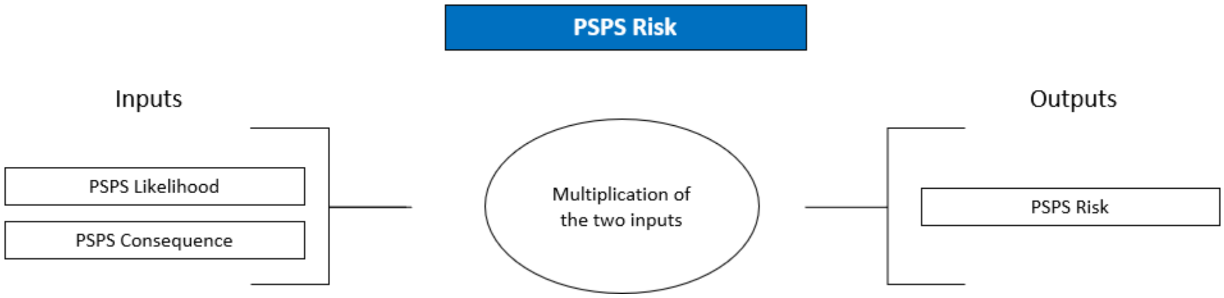
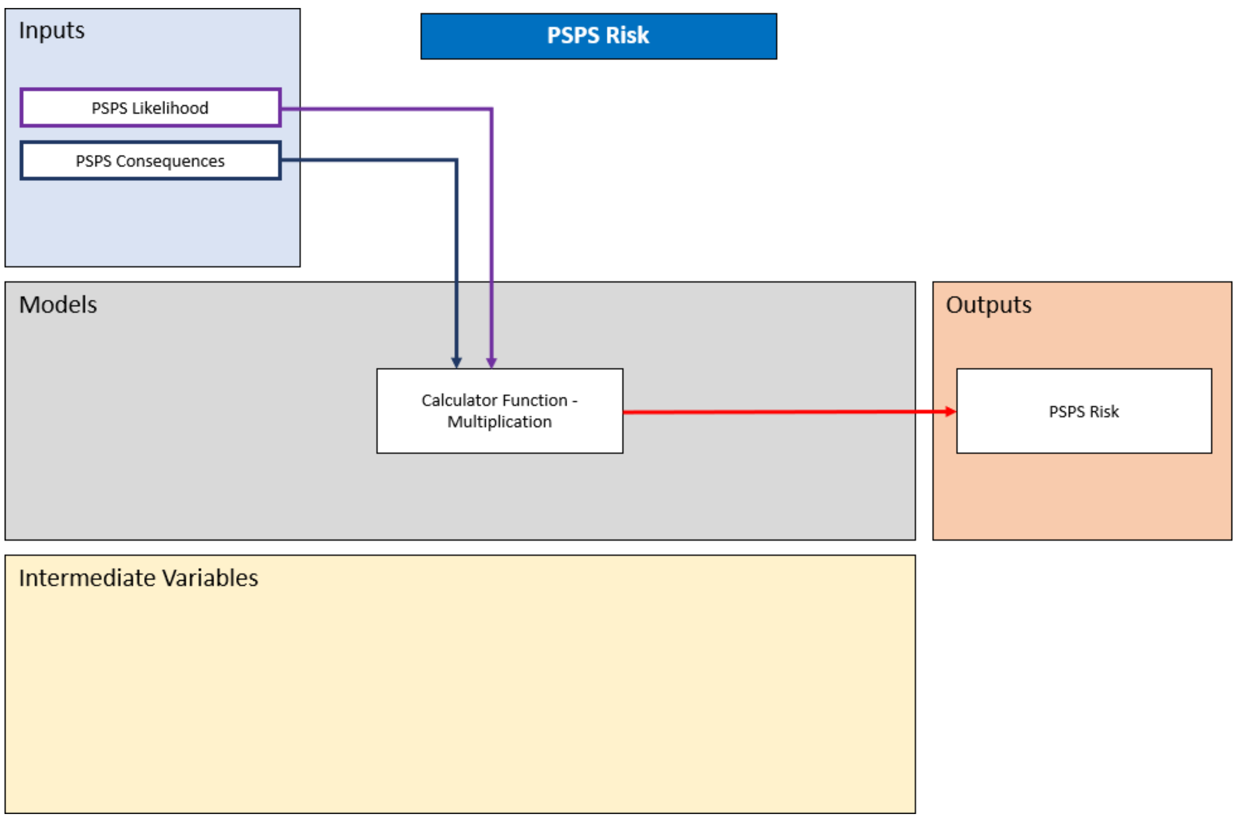


Figure SCE B-12: SCE's PSPS Risk Calculation Procedure Schematic



Purpose of the calculation/model

PSPS Risk (IRC4) is calculated based on two inputs – PSPS Likelihood (IRC5) and PSPS Consequence (IRC6).

Assumptions and limitations

The risk calculation is based on assumptions and limitations from more granular sub-components – PSPS Likelihood and PSPS Consequence.

Description of the calculation procedure shown in the bow tie and high-level schematics

PSPS Risk is a product of PSPS Likelihood and PSPS Consequence.

Description of how outputs will be characterized and presented (e.g., visualization) to decision makers

PSPS Risk components (likelihood and consequence) can be shown individually or shown as a single risk score per circuit, depending on the purpose of the presentation.

Concise description and timeline of planned changes to the calculation procedure over the triennial WMP cycle.

PSPS Risk is a composition of the individual sub-components. Please refer to the individual sub-components for description and timeline of key improvements.

IRC5: PSPS Likelihood

Figure SCE B-13: SCE's PSPS Likelihood Bow Tie Schematic

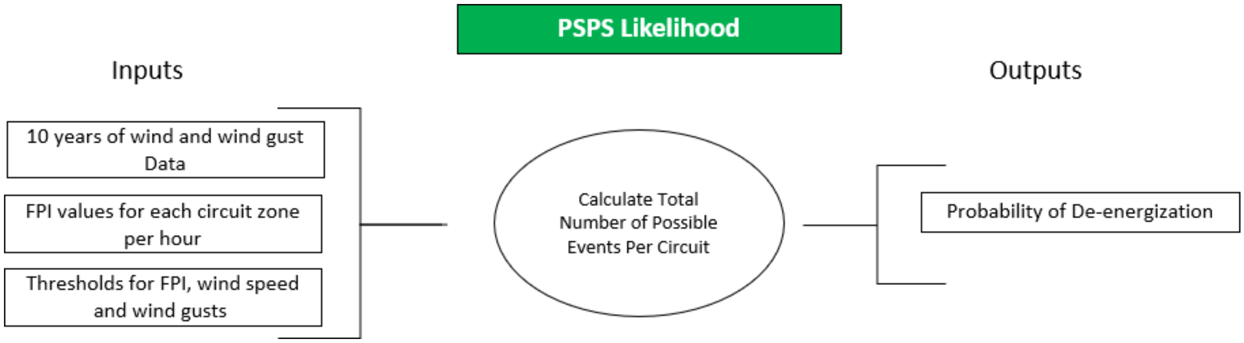
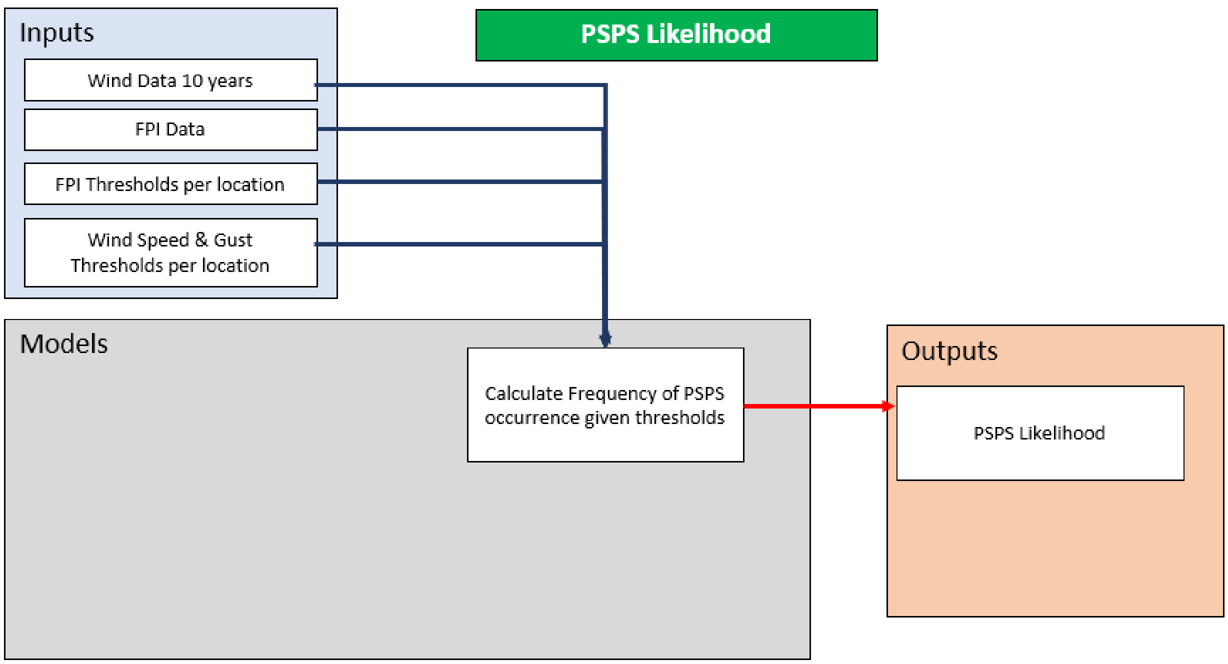


Figure SCE B-14: SCE's PSPS Likelihood Calculation Procedure Schematic



Purpose of the calculation/model

SCE considers PSPS Likelihood as synonymous with Probability of De-energization (POD). POD is used to estimate the projected frequency and duration of future PSPS events.

Assumptions and limitations

SCE assumes future wind conditions will resemble past conditions. Additionally, SCE assumes current de-energization thresholds will remain in place.

Description of the calculation procedure shown in the bow tie and high-level schematics

Depending on the current state of grid hardening on each individual circuit, the Probability of De-energization is based on the frequency and duration estimates in terms of total annual hours for each circuit. SCE utilizes de-energization thresholds based on historical wind speed, wind gusts conditions and hourly FPI values to approximate the likely frequency, and duration of PSPS events for both hardened and unhardened circuits. See De-Energization Thresholds in Table SCE B-01 below.

Description of how outputs will be characterized and presented (e.g., visualization) to decision makers

Table SCE B-01 provides the general de-energization thresholds of hardened and unhardened circuits. The hardened or unhardened calculated exceedance will determine the projected frequency and duration of future PSPS events.

Table SCE B-01: De-energization Thresholds[213]

Unhardened Thresholds	**FPI > 12 AND Wind (Sustained) > 31 mph OR Wind (Gust) > 46 mph**
Hardened Thresholds	FPI > 13 in all Fire Climate Zones (FCZs) except Zone 1 “Coastal” where FPI > 12 is used AND Wind (Sustained) > 40 mph OR Wind (Gust) > 58 mph.

Concise description and timeline of planned changes to the calculation procedure over the triennial WMP cycle.

In addition to the improvements listed in Section 5.7, SCE will review feedback from the Wildfire Risk Modeling Working group and other stakeholder forums to assess key improvements or changes.

213 Thresholds may be adjusted in an actual PSPS event based on the risks and complexities associated with the event and the specific risk factors associated with each circuit. Information on specific threshold adjustments can be found in the PSPS-post event reports for each event.

IRC6: PSPS Consequence

Figure SCE B-15: SCE's PSPS Consequence Bow Tie Schematic

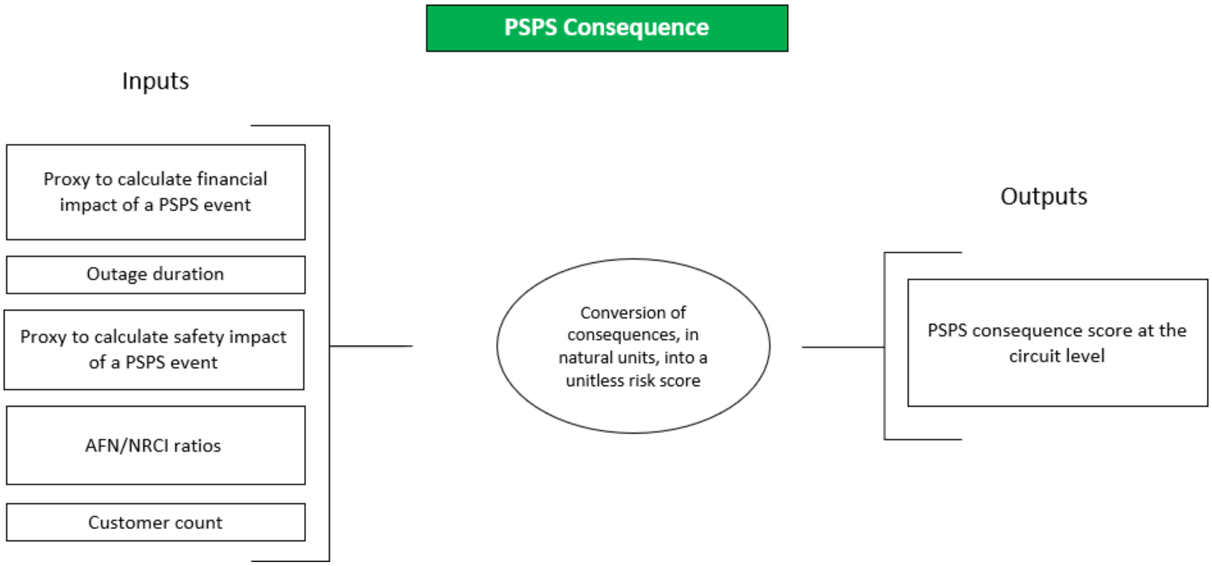
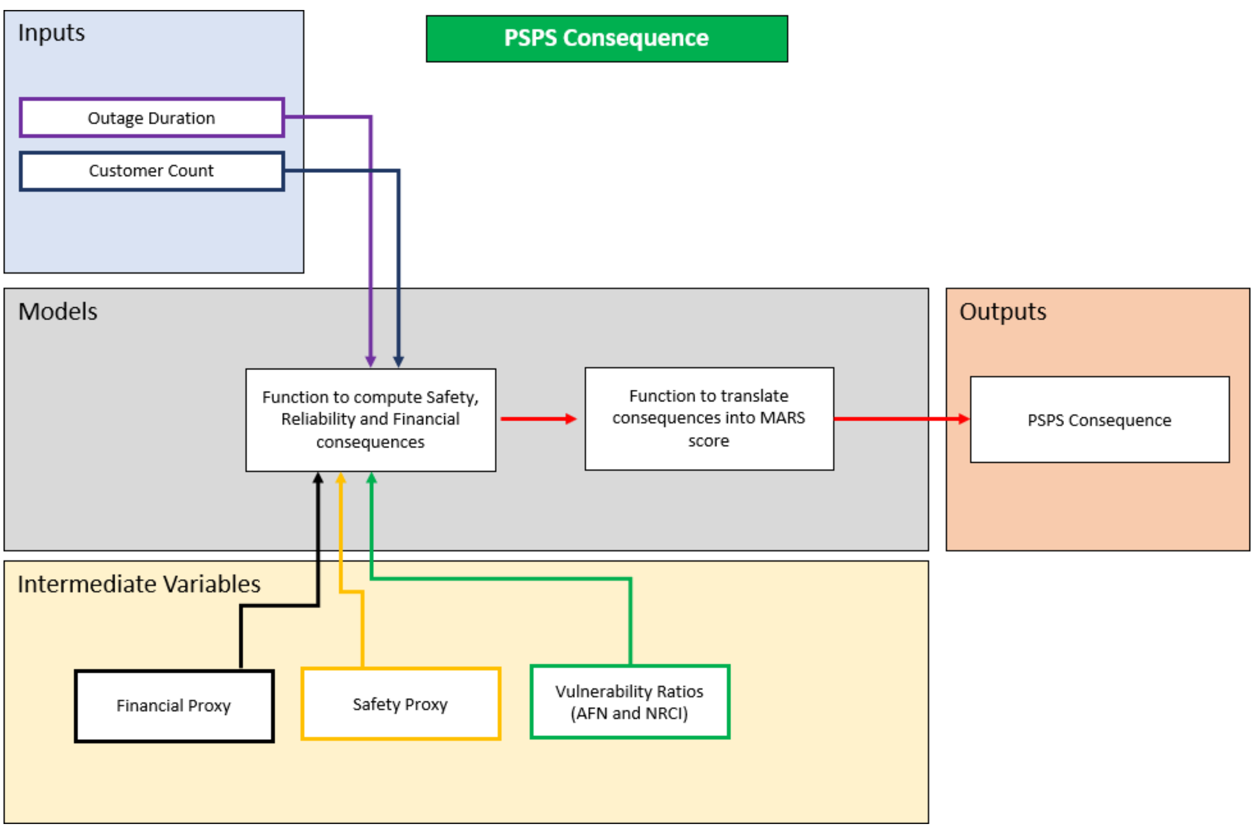


Figure SCE B-16: SCE's PSPS Consequence Calculation Procedure Schematic



Purpose of the calculation/model

PSPS Consequence is used, in conjunction with PSPS Vulnerability, to assess the impact of potential consequences associated with a proactive de-energization event. PSPS Consequence (IRC6) calculates the consequence components (Safety, Reliability, and Financial) from a PSPS event and then translates it into a MARS score.

Assumptions and limitations

This component assumes an 8-hour outage duration, which was chosen to be consistent with the duration of the wildfire simulation. In addition, SCE developed proxies to convert customers' outage duration into financial and safety consequence. Limitations can include using a singular proxy value for safety and especially financial consequence, acknowledging that there can be a broad range of outcomes.

Description of the calculation procedure shown in the bow tie and high-level schematics

SCE takes two inputs, number of customers and outage duration, in combination with the financial and safety proxies to compute safety, reliability and financial consequence as described in Section 5.2.2.2.2.7. A PSPS vulnerability multiplier is applied to the safety component to factor in access and functional needs customers and non-residential critical infrastructure. The last step is to translate the consequence, in natural units of measurement, to a unitless MARS risk score using the MAVF framework.

Description of how outputs will be characterized and presented (e.g., visualization) to decision makers

The consequence components of safety, reliability and financial can be presented individually or in aggregate at the circuit level, depending on the purpose of the presentation.

Concise description and timeline of planned changes to the calculation procedure over the triennial WMP cycle.

In addition to the improvements listed in Section 5.7, SCE will review feedback from the Wildfire Risk Modeling Working group and other stakeholder forums to assess key improvements or changes.

IRC7: PEDS Outage Risk

Figure SCE B-17: SCE's PEDS Risk Bow Tie Schematic

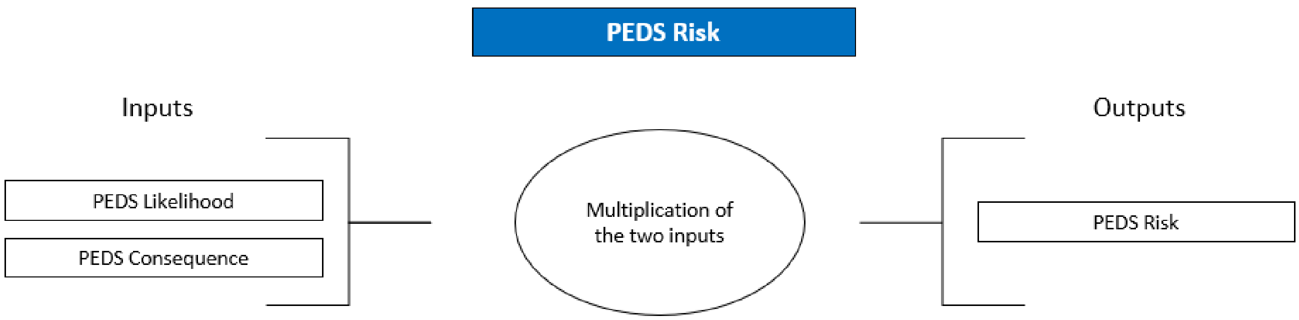
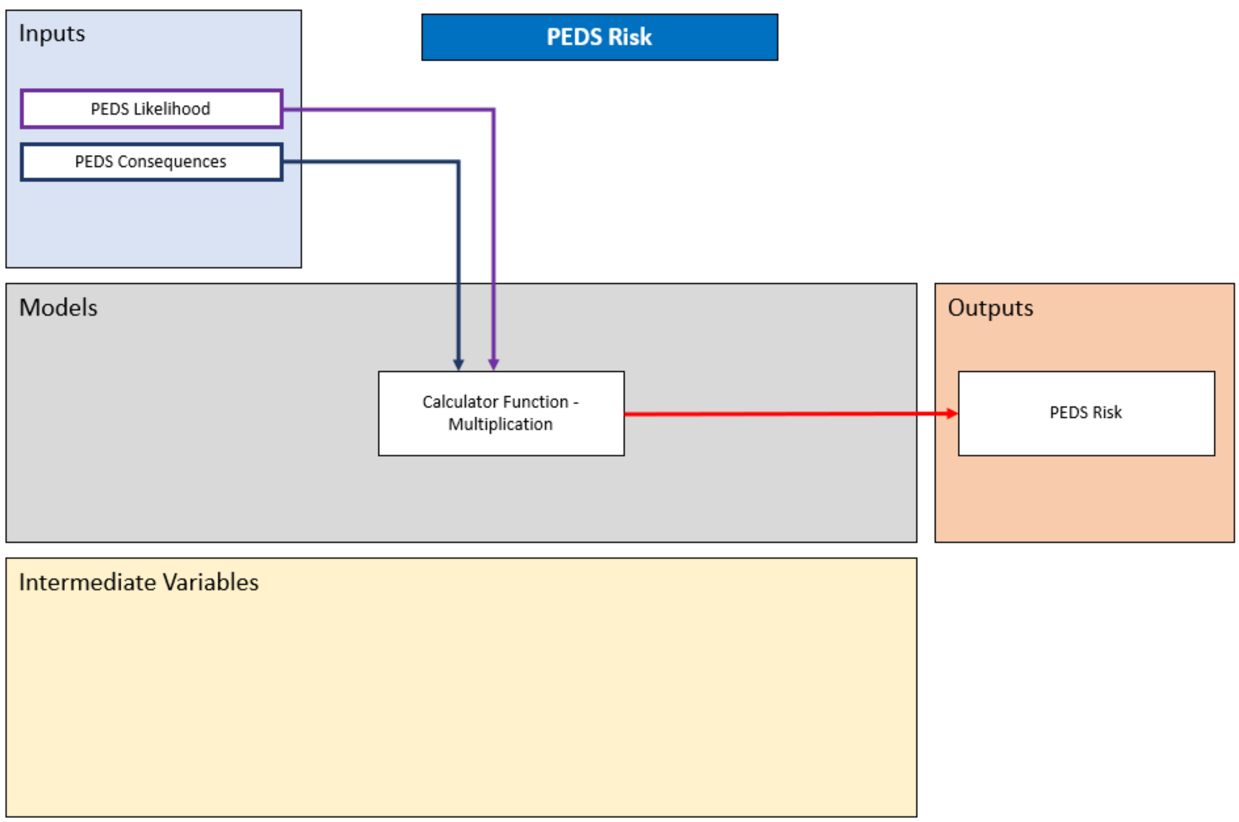


Figure SCE B-18: SCE's PEDS Risk Calculation Procedure Schematic



Purpose of the calculation/model

PEDS Outage Risk (IRC7) is calculated based on two inputs – PEDS Outage Likelihood (IRC8) and PEDS Outage Consequence (IRC9).

Assumptions and limitations

The risk calculation is based on assumptions and limitations from more granular sub-components – PEDS Outage Likelihood and PEDS Outage Consequence.

Description of the calculation procedure shown in the bow tie and high-level schematics

PEDS Risk is a product of PEDS Outage Likelihood and PEDS Outage Consequence.

Description of how outputs will be characterized and presented (e.g., visualization) to decision makers

PEDS Risk components (likelihood and consequence) can be shown individually or shown as a single risk score per circuit, depending on the purpose of the presentation.

Concise description and timeline of planned changes to the calculation procedure over the triennial WMP cycle.

PEDS Risk is a composition of the individual sub-components. Please refer to the individual sub-components for description and timeline of key improvements.

IRC8: PEDS Outage Likelihood

Figure SCE B-19: SCE's PEDS Outage Likelihood Bow Tie Schematic

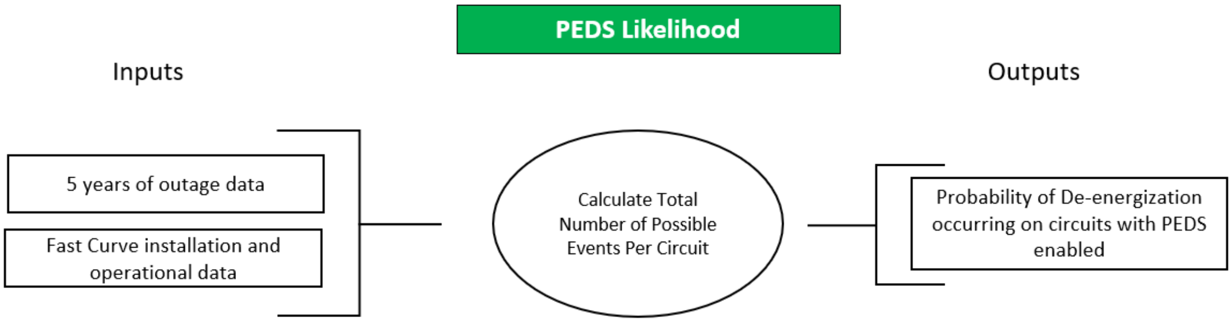
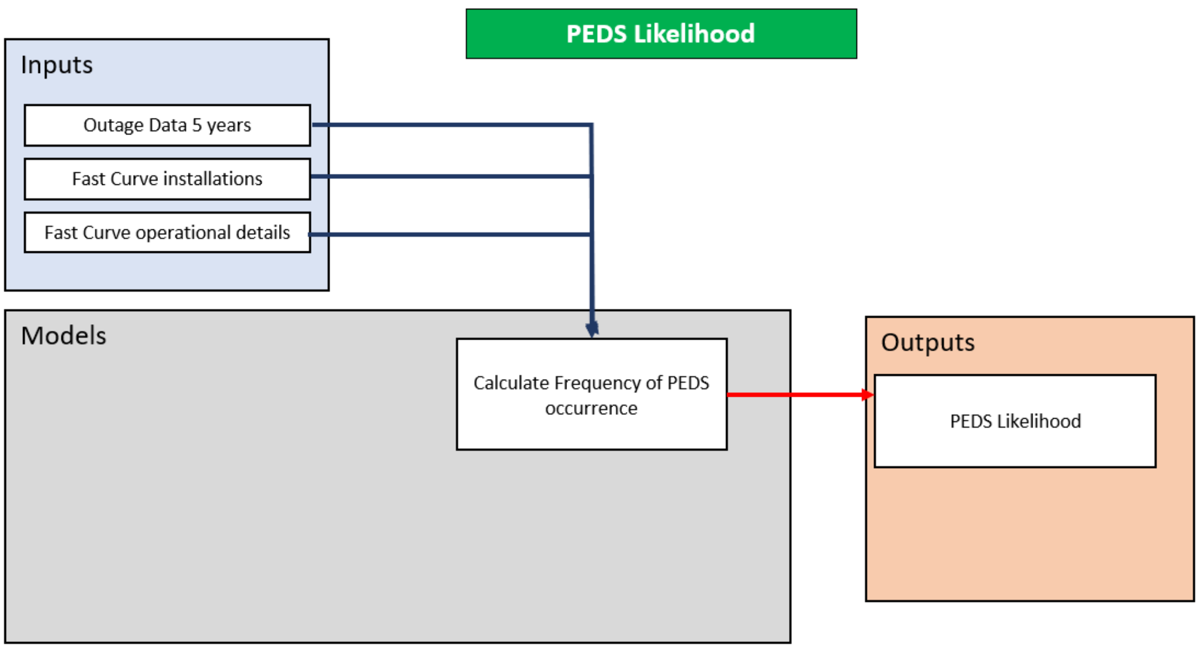


Figure SCE B-20: SCE's PEDS Outage Likelihood Calculation Procedure Schematic



Purpose of the calculation/model

PEDS Outage Likelihood is used to estimate the projected frequency of outages occurring while PEDS are enabled.

Assumptions and limitations

SCE assumes future wind conditions, including Red Flag Warning days, will resemble past conditions.

Description of the calculation procedure shown in the bow tie and high-level schematics

SCE utilizes historical outages on Fast-Curve enabled circuits and considers that Fast Curve settings were installed and are enabled at different times of the year to approximate the likely frequency of PEDS events by circuit.

Description of how outputs will be characterized and presented (e.g., visualization) to decision makers

The likelihood can be presented individually at the circuit level.

Concise description and timeline of planned changes to the calculation procedure over the triennial WMP cycle.

In addition to the improvements listed in Section 5.7, SCE will review feedback from the Wildfire Risk Modeling Working group and other stakeholder forums to assess key improvements or changes.

IRC9: PEDS Outage Consequence

Figure SCE B-21: SCE's PEDS Outage Consequence Bow Tie Schematic

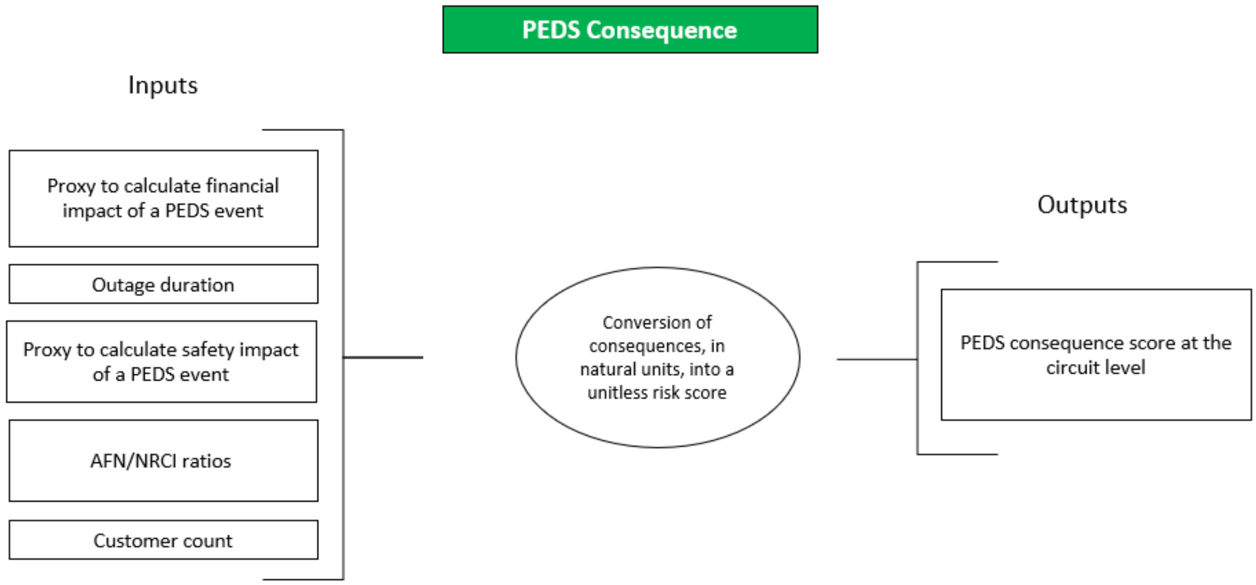
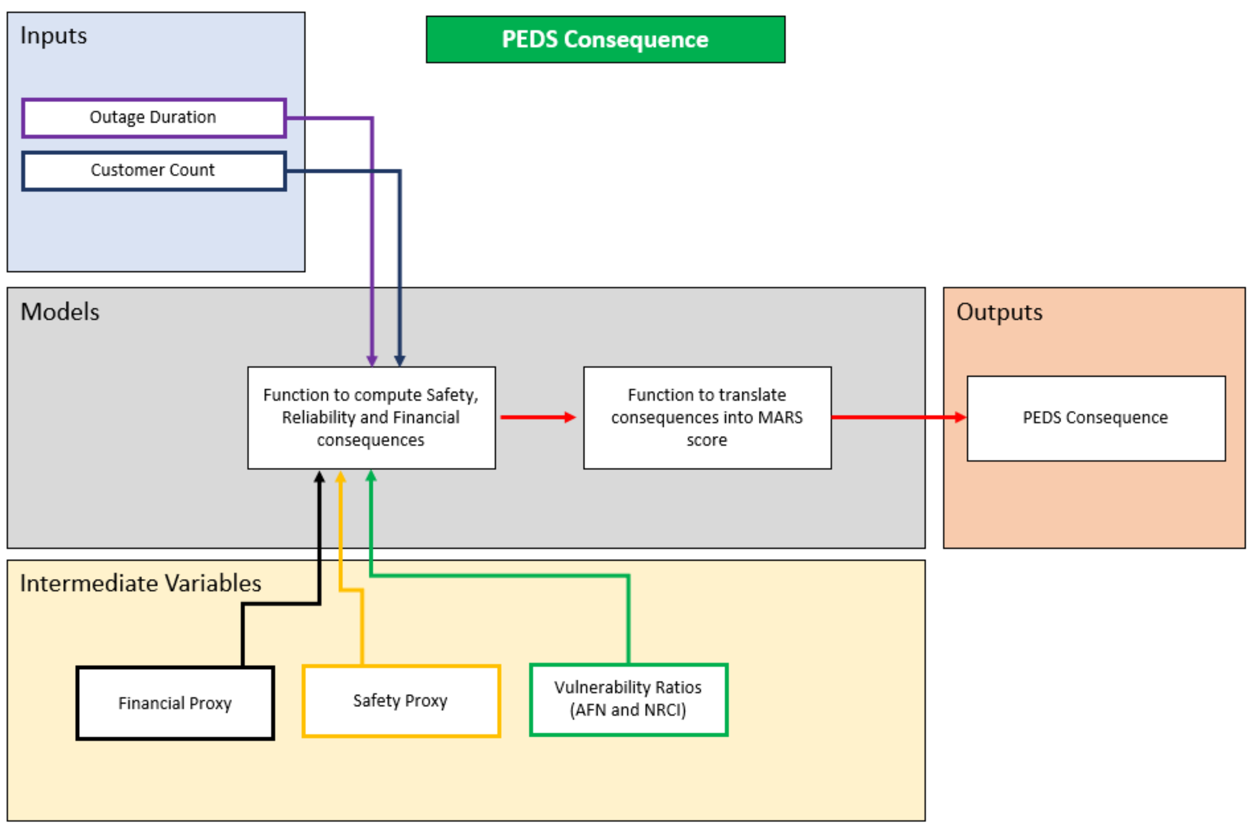


Figure SCE B-22: SCE's PEDS Outage Consequence Calculation Procedure Schematic



Purpose of the calculation/model

PEDS Outage Consequence (IRC9) is used, in conjunction with PEDS Vulnerability, to assess the increased impact to customers with a potential increase in CMI when Fast Curve is enabled.

Assumptions and limitations

This component estimates the increased number of impacted customers and increased outage duration based on 5 years of historical data of outages on Fast-Curve (FC) enabled circuits. The customer count and duration consider available protection schema and outage scenarios. In addition, SCE developed proxies to convert customers' outage duration into financial and safety consequence. Limitations can include using a singular proxy value for safety and especially financial consequence, acknowledging that there can be a broad range of outcomes.

Description of the calculation procedure shown in the bow tie and high-level schematics

SCE takes two inputs, number of customers and outage duration, in combination with the financial and safety proxies to compute safety, reliability and financial consequence as described in Section 5.2.2.2.2.7. A PEDS vulnerability multiplier is applied to the safety component to factor in access and functional needs (AFN) and non-residential critical infrastructure (NRCI) customers. The last step is to translate the consequence, in natural units of measurement, to a unitless MARS risk score using the MAVF framework.

Description of how outputs will be characterized and presented (e.g., visualization) to decision makers

The consequence components of safety, reliability and financial can be presented individually or in aggregate at the circuit level, depending on the purpose of the presentation.

Concise description and timeline of planned changes to the calculation procedure over the triennial WMP cycle.

In addition to the improvements listed in Section 5.7, SCE will review feedback from the Wildfire Risk Modeling Working group and other stakeholder forums to assess key improvements or changes.

FRC1: Equipment Caused Ignition Likelihood

Figure SCE B-23: SCE's Equipment Caused Ignition Likelihood Bow Tie Schematic

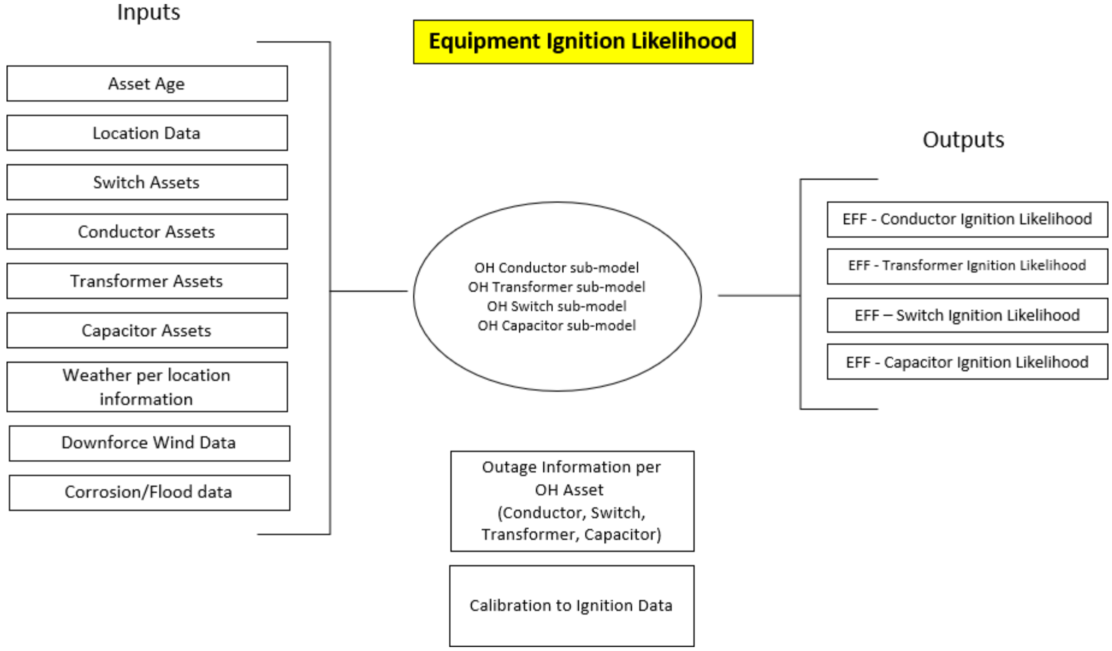
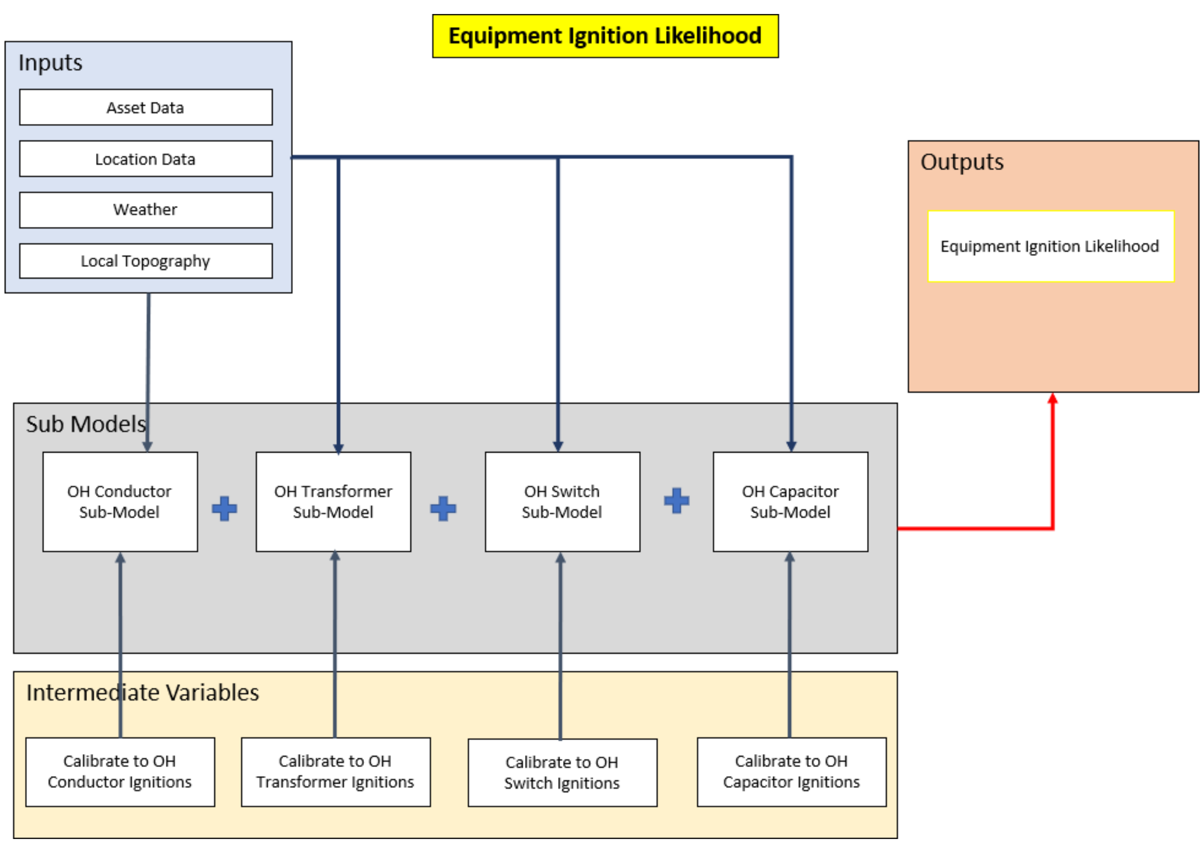


Figure SCE B-24: SCE's Equipment Caused Ignition Likelihood Calculation Procedure Schematic



Purpose of the calculation/model

Equipment Caused Ignition Likelihood (FRC1), a subcomponent of Ignition Likelihood (IRC2), calculates the likelihood that electrical corporation-owned equipment will cause an ignition either through normal operation (such as arcing) or through failure.

Assumptions and limitations

The probability of ignition of an Equipment/Facility Failure (EFF POI) is a probabilistic assessment of each asset's pre-mitigated ignition likelihood prior to mitigation deployment.

Description of the calculation procedure shown in the bow tie and high-level schematics

EFF POI is the sum of the ignition component probabilities at that location of the ignition component sub models (e.g. conductor POI, transformer POI, switch POI, capacitor POI). These subcomponent asset models utilize machine learning (ML) algorithms to assess the relevance of ignition drivers relevant to that subcomponent type. Each EFF related subcomponent model uses historical asset outage data, current asset condition (e.g., age, voltage, inspection results, etc.) and relevant environmental attributes (e.g. historical wind, asset loading, number of customers, temperature, relative humidity, etc.). Each model is calibrated with associated outage data for the OH asset type and ignition data.

Description of how outputs will be characterized and presented (e.g., visualization) to decision makers

Equipment Caused Ignition Likelihood can be broken down into its subcomponents for each asset model or shown in aggregate for overall SCE system EFF POI depending on the purpose of the presentation.

Concise description and timeline of planned changes to the calculation procedure over the triennial WMP cycle.

In addition to the improvements listed in Section 5.7 SCE will review feedback from the Wildfire Risk Modeling Working group and other stakeholder forums to assess key improvements or changes.

FRC2: Contact from Vegetation Likelihood of Ignition

Figure SCE B-25: SCE's Contact from Vegetation Likelihood of Ignition Bow Tie Schematic

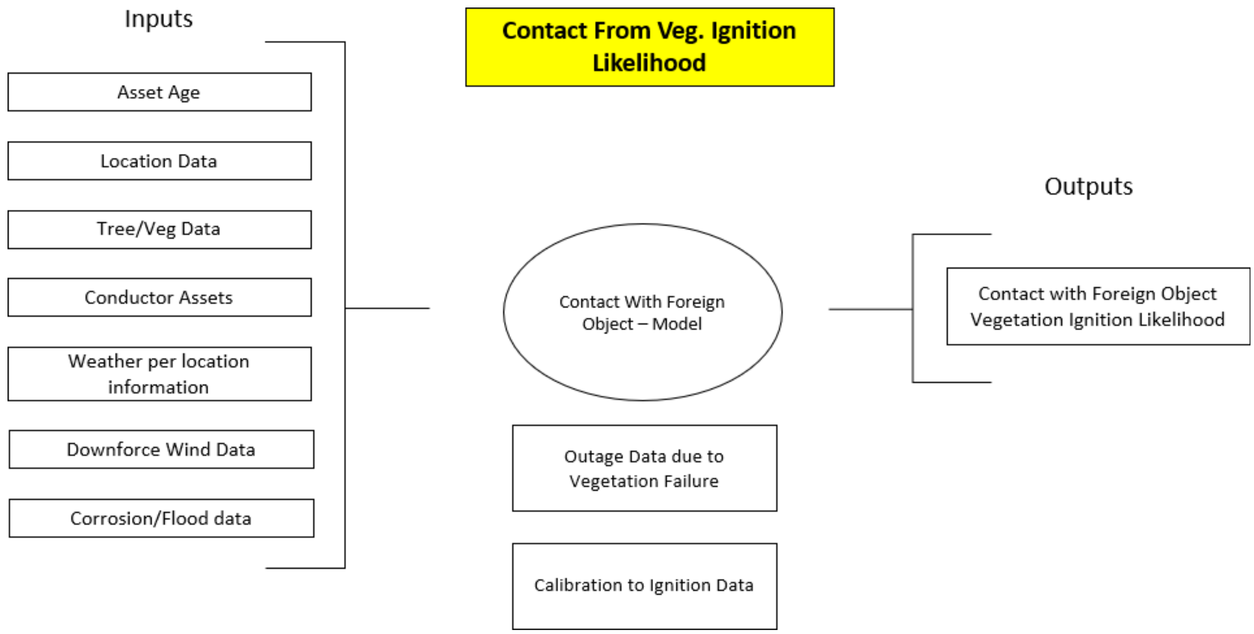
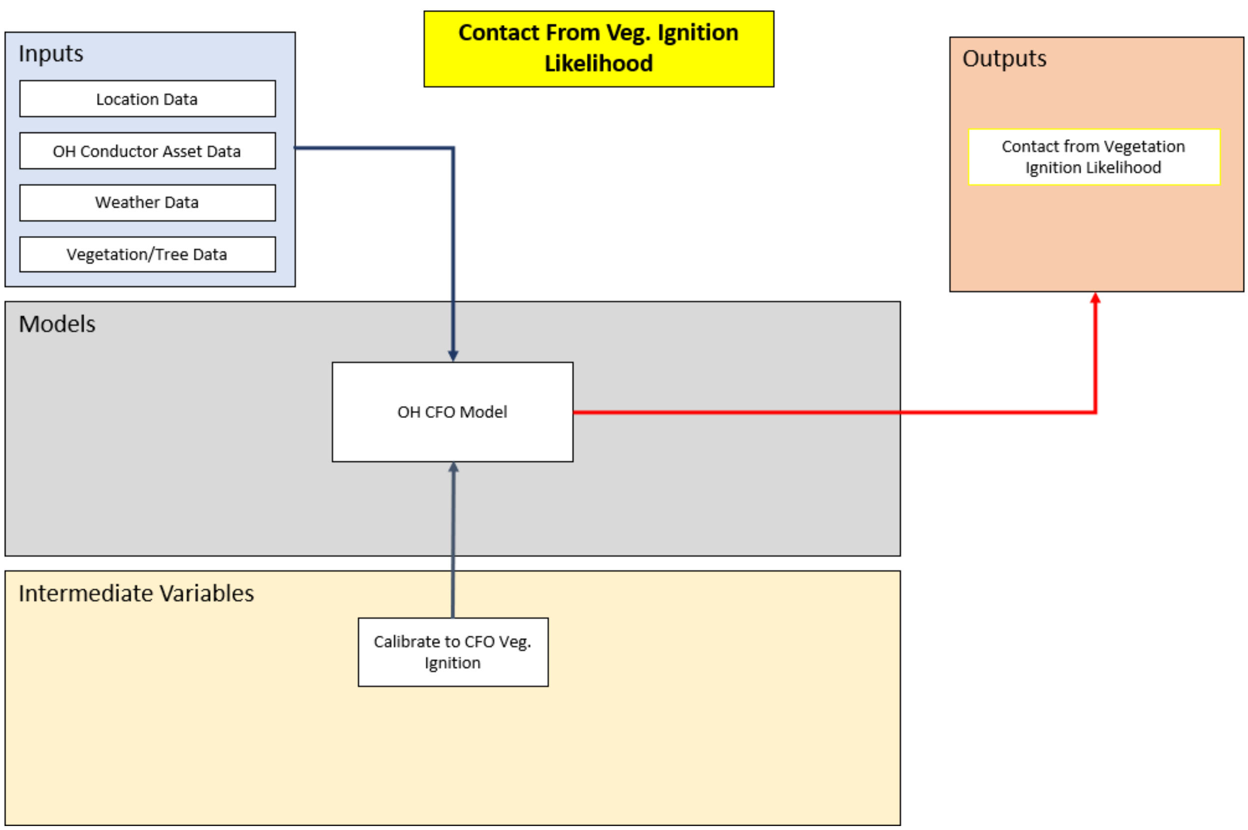


Figure SCE B-26: SCE's Contact from Vegetation Likelihood of Ignition Calculation Procedure Schematic



Purpose of the calculation/model

Contact from Vegetation Likelihood of Ignition (FRC2), a subcomponent of Ignition Likelihood (IRC2), calculates the likelihood that vegetation will contact electrical corporation-owned equipment and cause an ignition either through a fault or arcing event at a given location.

Assumptions and limitations

The probability of ignition of a Contact from Foreign Object - Vegetation (CFO-Veg POI) is probabilistic assessment of each asset's pre-mitigated ignition likelihood prior to mitigation deployment.

Description of the calculation procedure shown in the bow tie and high-level schematics

CFO-Veg POI is the output of the Contact from Foreign Object model that utilizes machine learning (ML) algorithms to assess the relevance of ignition sub-drivers relevant to vegetation sub-drivers. The CFO model uses historical asset outage data, current asset condition (e.g., age, voltage, inspection results, etc.) and relevant environmental attributes (e.g. historical wind, asset loading, number of customers, temperature, relative humidity, etc.). The model is calibrated with associated outage data and ignition data.

Description of how outputs will be characterized and presented (e.g., visualization) to decision makers

Contact from Vegetation Likelihood of Ignition is a subcomponent of the CFO Model and is typically shown in conjunction with other CFO sub-drivers (as detailed in Contact from Object Ignition Likelihood (FRC3).

Concise description and timeline of planned changes to the calculation procedure over the triennial WMP cycle.

In addition to the improvements listed in Section 5.7, SCE will review feedback from the Wildfire Risk Modeling Working group and other stakeholder forums to assess key improvements or changes.

FRC3: Contact from Object Likelihood of Ignition

Figure SCE B-27: SCE's Contact from Object Likelihood of Ignition Bow Tie Schematic

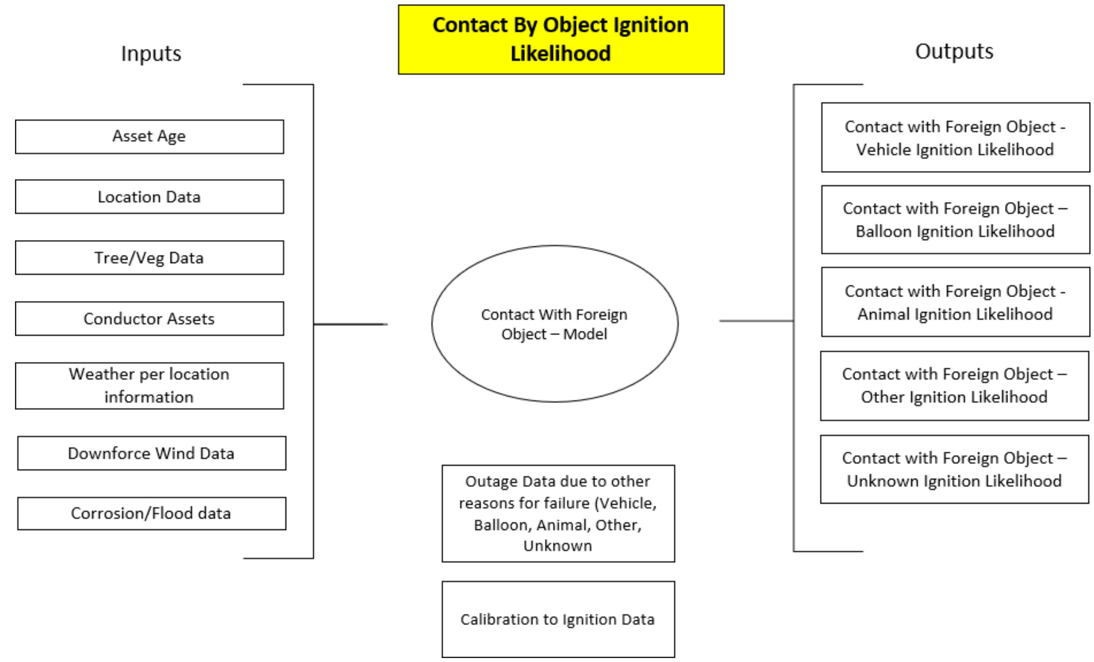
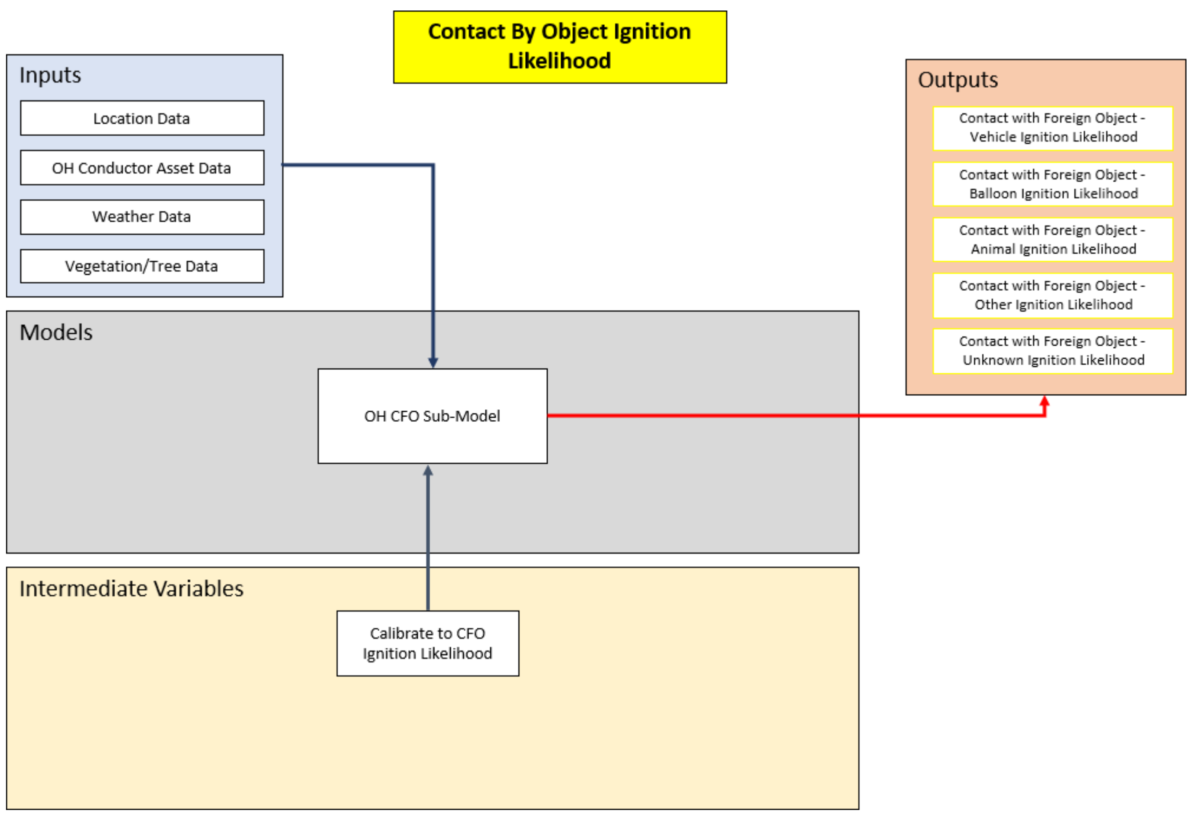


Figure SCE B-28: SCE's Contact from Object Likelihood of Ignition Calculation Procedure Schematic



Purpose of the calculation/model

Contact from Object Ignition Likelihood (FRC3), a subcomponent of Ignition Likelihood (IRC2), calculates the likelihood that a non-vegetative object (e.g., vehicle, balloon, animal, other, unknown) will contact electrical corporation-owned equipment and cause an ignition either through a fault or arcing event at a given location.

Assumptions and limitations

The probability of ignition of a Contact from Foreign Object (CFO POI) is a probabilistic assessment of each asset's pre-mitigated ignition likelihood prior to mitigation deployment.

Description of the calculation procedure shown in the bow tie and high-level schematics

CFO POI is the output of the Contact from Foreign Object model that utilizes machine learning (ML) algorithms to assess the relevance of ignition sub-drivers relevant to non-vegetative sub-drivers (e.g. vehicle, balloon, animal, other, unknown). The CFO model uses historical asset outage data, current asset condition (e.g., age, voltage, inspection results, etc.) and relevant environmental attributes (e.g. historical wind, asset loading, number of customers, temperature, relative humidity, etc.). The model is calibrated with associated outage data for each sub-driver and ignition data.

Description of how outputs will be characterized and presented (e.g., visualization) to decision makers

Contact from Object Ignition Likelihood are subcomponents of the CFO Model and is typically shown in conjunction with other CFO sub-drivers (as detailed in Contact from Vegetation Likelihood of Ignition (FRC2)).

Concise description and timeline of planned changes to the calculation procedure over the triennial WMP cycle.

In addition to the improvements listed in Section 5.7, SCE will review feedback from the Wildfire Risk Modeling Working group and other stakeholder forums to assess key improvements or changes.

FRC4: Burn Likelihood

Please see Sections 5.2.1.5 and 5.2.2.1 for SCE's approach to this risk component.

FRC5: Wildfire Hazard Intensity

Please see Sections 5.2.1.5 and 5.2.2.2.3 for SCE's approach to this risk component.

FRC6: Wildfire Exposure Potential

Please see Sections 5.2.1.5 and 5.2.2.2.3 for SCE's approach to this risk component.

FRC7: Wildfire Vulnerability

Figure SCE B-29: SCE's Wildfire Vulnerability Bow Tie Schematic

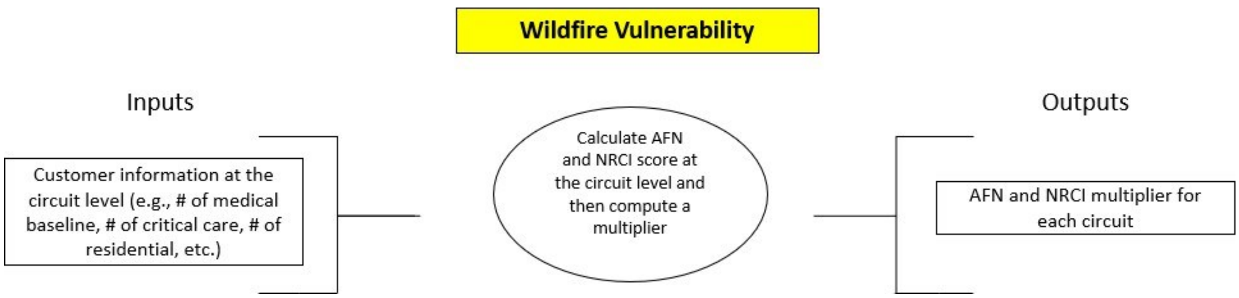
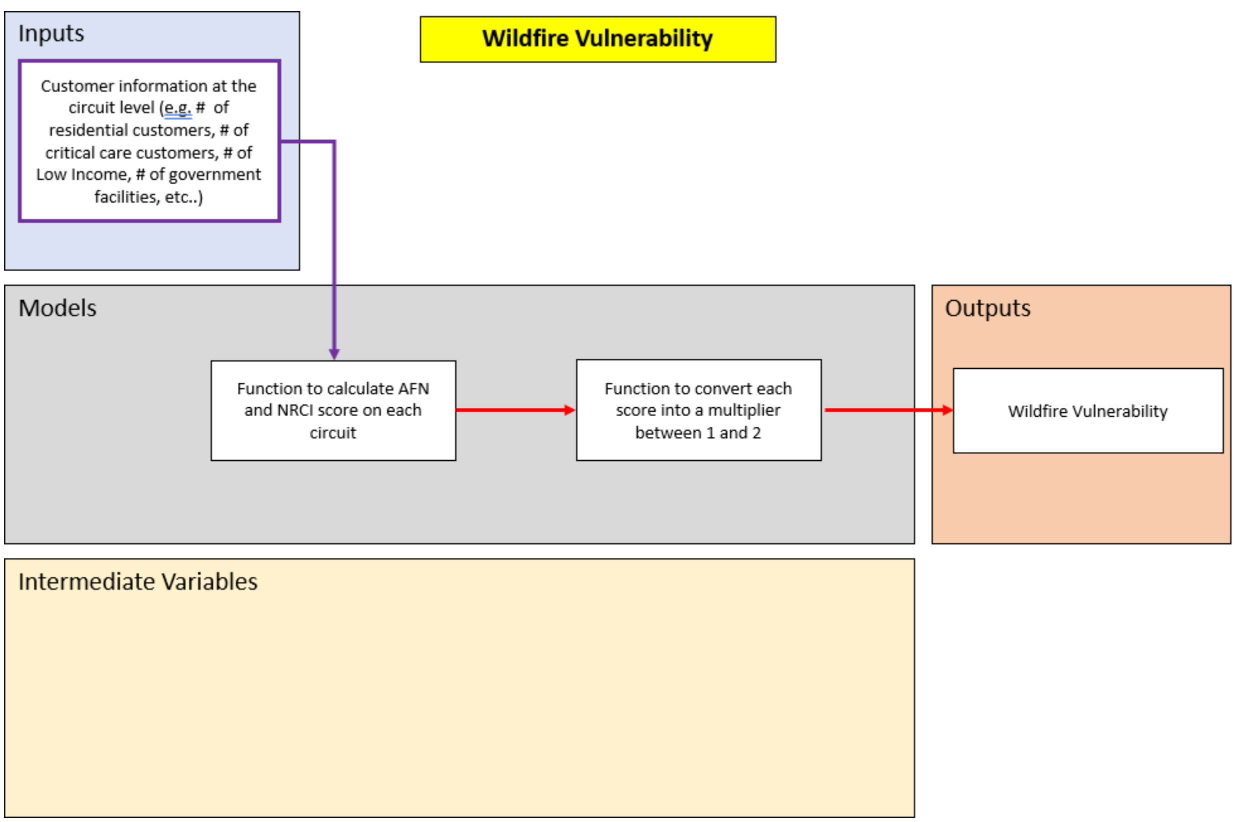


Figure SCE B-30: SCE's Wildfire Vulnerability Calculation Procedure Schematic



Purpose of the calculation/model

Wildfire Vulnerability (FRC7) calculates the AFN/NRCI multiplier to be used as an amplifier to the Wildfire Safety consequence.

Assumptions and limitations

SCE assumes certain weightings for AFN characteristics (# of critical care, # of medical baseline, etc.) in its formulation of a composite score at the circuit level. Limitations may include availability to the latest data or data lag.

Description of the calculation procedure shown in the bow tie and high-level schematics

The methodology to calculate the multiplier is described in Section 5.2.2.2.3. SCE takes the composite score on each circuit and develops a multiplier for each circuit based on the calculation below:

$$AFN_{CircuitMultiplier} = 1 + \frac{AFN_{Score_{circuit}}}{AFN_{Score_{MAX}}}$$

A similar framework is used to develop the NRCI multiplier.

Description of how outputs will be characterized and presented (e.g., visualization) to decision makers

The output is a multiplier that is used to amplify the Wildfire Safety Consequence. It is not viewed directly by decision makers because it is an intermediate calculation.

Concise description and timeline of planned changes to the calculation procedure over the triennial 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.

In addition to the improvements listed in Section 5.7, SCE will review feedback from the Wildfire Risk Modeling Working group and other stakeholder forums to assess key improvements or changes.

FRC8: PSPS Exposure Potential

Please see Section 5.2.1.5 for SCE's approach to this risk component.

FRC9: PSPS Vulnerability

Figure SCE B-31: SCE's PSPS Vulnerability Bow Tie Schematic

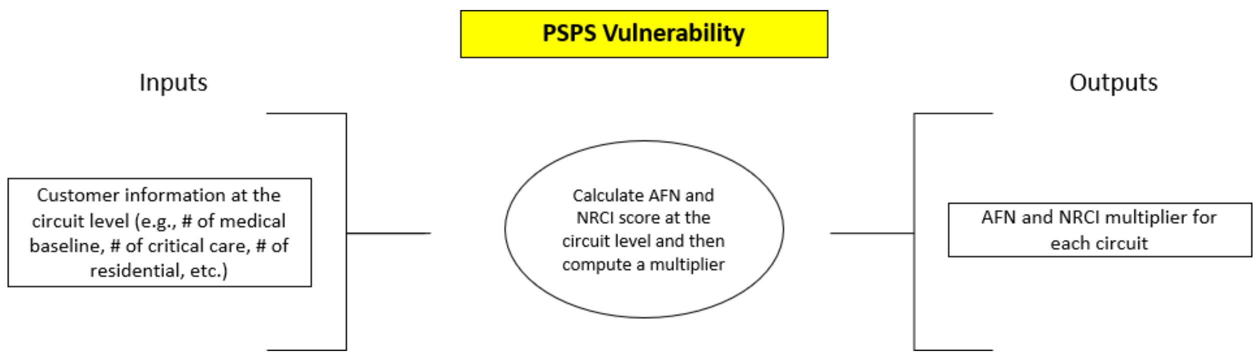
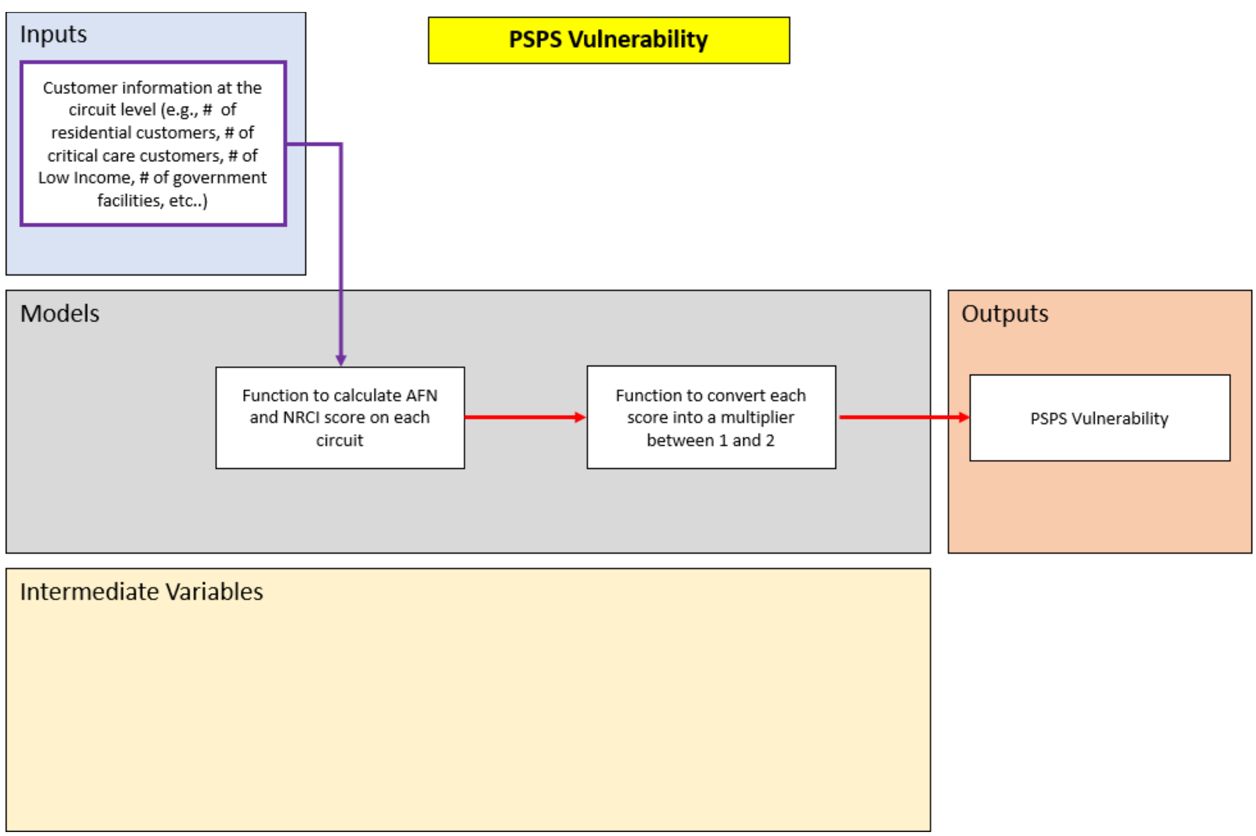


Figure SCE B-32: SCE's PSPS Vulnerability Calculation Procedure Schematic



Purpose of the calculation/model

PSPS Vulnerability (FRC9) calculates the AFN/NRCI multiplier to be used as an amplifier to the PSPS Safety consequence.

Assumptions and limitations

SCE assumes certain weightings for AFN characteristics (# of critical care, # of medical baseline, etc.) in its formulation of a composite score at the circuit level. Limitations may include availability to the latest data or data lag.

Description of the calculation procedure shown in the bow tie and high-level schematics

The methodology to calculate the multiplier is described in Section 5.2.2.3. SCE takes the composite score on each circuit and develops a multiplier for each circuit based on the calculation below:

$$AFN_{CircuitMultiplier} = 1 + \frac{AFN_{Score_{circuit}}}{AFN_{Score_{MAX}}}$$

A similar framework is used to develop the NRCI multiplier.

Description of how outputs will be characterized and presented (e.g., visualization) to decision makers

The output is a multiplier that is used to amplify the PSPS Safety Consequence. It is not viewed directly by decision makers because it is an intermediate calculation.

Concise description and timeline of planned changes to the calculation procedure over the triennial 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.

In addition to the improvements listed in Section 5.7, SCE will review feedback from the Wildfire Risk Modeling Working group and other stakeholder forums to assess key improvements or changes.

FRC10: PEDS Outage Exposure Potential

Please see Section 5.2.1.5 for SCE's approach to this risk component.

FRC11: PEDS Outage Vulnerability

Figure SCE B-33: SCE's PEDS Outage Vulnerability Bow Tie Schematic

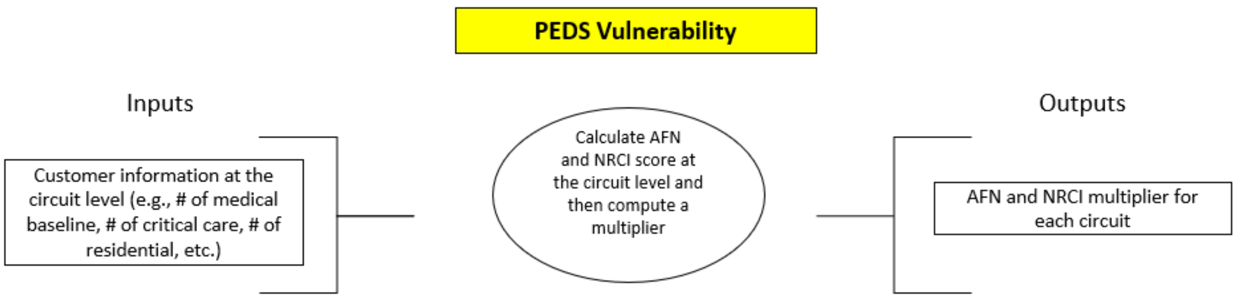
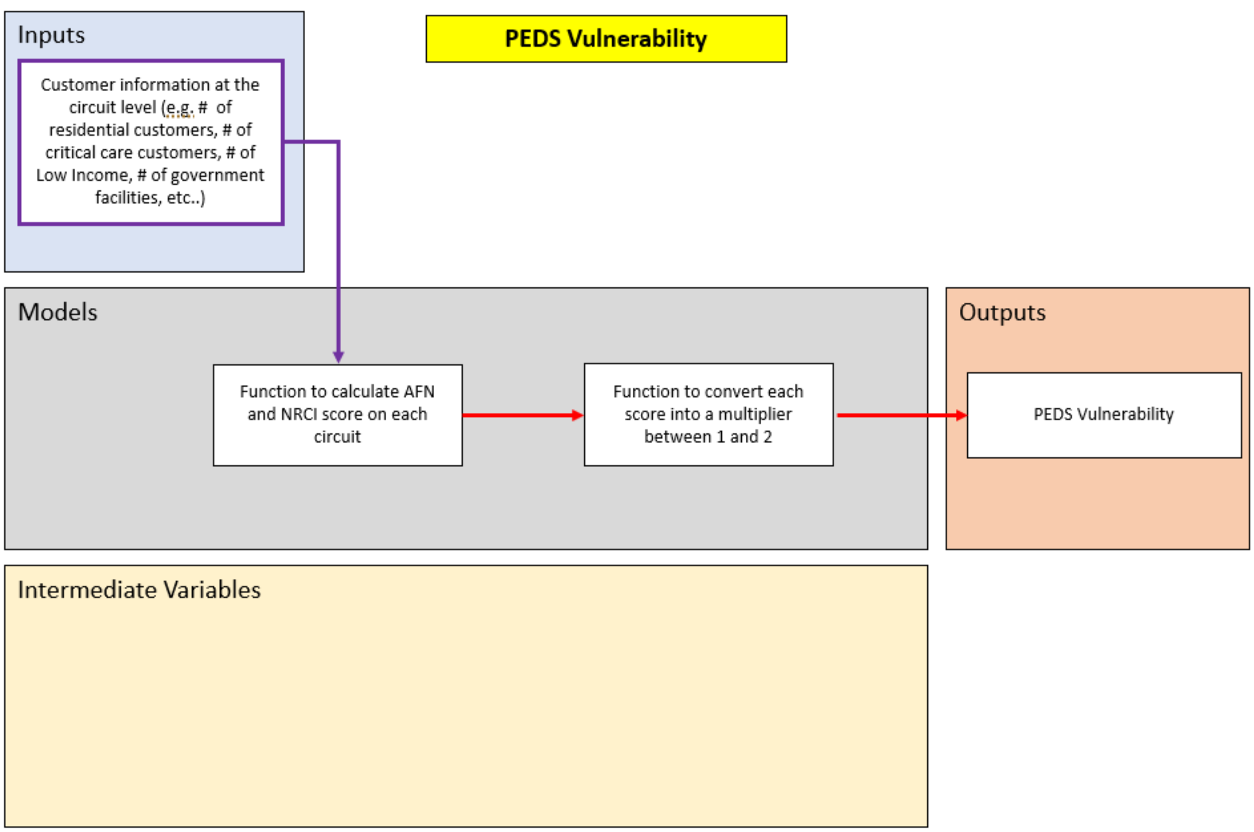


Figure SCE B-34: SCE's PEDS Vulnerability Calculation Procedure Schematic



Purpose of the calculation/model

PEDS Outage Vulnerability (FRC11) calculates the AFN/NRCI multiplier to be used as an amplifier to the PEDS Safety consequence.

Assumptions and limitations

SCE assumes certain weightings for AFN characteristics (# of critical care, # of medical baseline, etc.) in its formulation of a composite score at the circuit level. Limitations may include availability to the latest data or data lag.

Description of the calculation procedure shown in the bow tie and high-level schematics

The methodology to calculate the multiplier is described in Section 5.2.2.2.3. SCE takes the composite score on each circuit and develops a multiplier for each circuit based on the calculation below:

$$AFN_{CircuitMultiplier} = 1 + \frac{AFN_{Score_{circuit}}}{AFN_{Score_{MAX}}}$$

A similar framework is used to develop the NRCI multiplier.

Description of how outputs will be characterized and presented (e.g., visualization) to decision makers

The output is a multiplier that is used to amplify the PEDS Safety Consequence. It is not viewed directly by decision makers because it is an intermediate calculation.

Concise description and timeline of planned changes to the calculation procedure over the triennial 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.

In addition to the improvements listed in Section 5.7, SCE will review feedback from the Wildfire Risk Modeling Working group and other stakeholder forums to assess key improvements or changes.

APPENDIX C: ADDITIONAL MAPS

In this appendix, the electrical corporation must provide a (one) representative map within the main body of its WMP. Where electrical corporations need to provide additional maps for clarity (e.g., the scale is insufficiently large to show useful detail), the electrical corporation must host applicable and up-to-date geospatial layers on a publicly accessible web application and refer to the specific web address in appropriate places throughout its WMP. Additionally, the electrical corporation must host these layers until at least the submission of its subsequent WMP or otherwise directed by Energy Safety. The electrical corporation may not modify these publicly available layers without notifying Energy Safety.

Below is a list of the Base WMP Guidelines sections which require additional maps:

Section Number	***Section Title***
4.1	*Service Territory*
4.3	*Frequently Deenergized Circuits*
5.5.1.1	*Geospatial Maps of Top Risk Areas within the HFRA*

SCE has published geospatial layers publicly on https://www.sce.com/wmp for the following maps:

- Figure SCE 4-01: SCE Service Territory and Customer Meter Density Map, Section 4.1
- Figure SCE 4-02: SCE Service Territory and Electrical Infrastructure Map, Section 4.1
- Figure SCE 4-03: SCE Frequently De-energized Circuits, Section 4.3
- Figure SCE 5-13: Map of SCE IWMS Categories in HFRA, Section 5.2.1
- Figure SCE 5-54: Map of Top-Risk Areas within the SCE HFRA, Section 5.5.1.1
- Figure SCE 5-55: Map of Top-Risk Areas within the SCE HFRA and SCE Proposed Updates to the HFTD, Section 5.5.1.2

APPENDIX D: AREAS FOR CONTINUED IMPROVEMENT

In this appendix, the electrical corporation must provide responses to its areas for continued improvement as identified in the Decisions on the previous Base WMP and WMP Update in the following format:

Code and Title:

Description:

Required Progress:

Section and Page Number of Any Improvements:

[Electrical Corporation] Response:

Risk Methodology and Assessment

SCE-25U-01. Calculating Risk Scores Using Maximum Consequence Values

Description

SCE continues to use maximum consequence values, as opposed to probability distributions, to aggregate risk scores. While this is acceptable for the time being, as modeling advances, SCE needs to continue exploring the use of probability distributions.

Required Progress

SCE must continue to evaluate the use of probability distributions and probabilistic models instead of maximum consequence, including conducting a pilot that applies probabilistic distributions in place of maximum consequence in SCE's risk models. In its 2026-2028 Base WMP, SCE must:

1. *Report on how and where SCE could incorporate probability distributions in its risk models, including its Integrated Wildfire Mitigation Strategy (IWMS), and subsequent planning frameworks.*

2. *Report the results of a pilot that applies probabilistic distributions in place of maximum consequence in SCE's risk models.*

3. *SCE must provide a comparison of the results of the pilot to SCE's existing risk assessment strategy, and report on the benefits and drawbacks of both strategies.*

4. *SCE must provide an explanation of how the use of probabilistic distributions impacts its IWMS, including where probability distributions could be integrated into: decision-making, how risk tranches are designated, and how mitigations are selected.*

5. *Report on the evaluation of additional wildfire simulations and weather scenarios, as described in its 2025 WMP Update.*

6. *Report on any changes made to SCE's models and associated impacts relating to use of probability distributions as a result of the CPUC's Phase 3 Decision for risk-based decision-making frameworks.*

7. *Provide a description of any additional steps SCE is taking to explore the use of probability distributions in the future.*

Section and Page Number of Any Improvements*: Section* 3.4 p.12, 5.1 p. 39, 5.2 p. 40, 5.3.2 p.117, and Appendix B

SCE Response

Required Progress Item #1: Report on how and where SCE could incorporate probability distributions in its risk models, including its Integrated Wildfire Mitigation Strategy (IWMS), and subsequent planning frameworks.

With Fire Sight 8, SCE currently includes a full range of probability distributions in its risk models. See Section 5.2 for further discussion.

Required Progress item #2a: SCE must provide a comparison of the results of the pilot to SCE's existing risk assessment strategy, and report on the benefits and drawbacks of both strategies.

As a threshold clarification, using probabilistic distributions is not the same as using mean value consequences (mean value and maximum value are simply options within a probabilistic distribution). Notwithstanding this distinction, based on the 2025 ACI, SCE adjusted its wildfire risk model to incorporate a fuller range of fire weather days, from which probability distributions at each location can be derived. See Section 5.2.2.2.2.2 for details on this approach.

SCE examined how mean value consequences would impact its IWMS framework, which uses a 300-acre threshold for High Consequence Areas (HCA) and a 10,000-acre threshold for Severe Risk Areas (SRA). As shown in the table below, SCE found that applying mean consequence values (i.e., 50 percent burn) at 8-hour burn simulations resulted in a reduction of 29% and 97% in SCE facilities that reached those HCA and SRA thresholds, respectively, for maximum consequence (100 percent burn). However, using mean consequence values at 24-hour burn simulations, similar to other utilities, resulted in an increase in SCE facilities that reached the 300-acre and 10,000-acre thresholds, with the latter showing a 500% increase (i.e., from 9.3% to 54.9% in the figure below).

Table SCE D-01: % SCE FLOCS and Simulated Acres Burned

Percent Burn	% FLOCs >300 Acres Burned 8h Burn	% FLOCs >300 Acres Burned 24h Burn	% FLOCs >10K Acres Burned 8h Burn	% FLOCs >10K Acres Burned 24h Burn
20	38.60%	65.70%	0.00%	4.00%
40	48.50%	70.30%	0.10%	12.50%
50	51.60%	71.80%	0.30%	16.00%
60	54.10%	73.20%	0.50%	19.40%
80	60.40%	76.60%	1.00%	28.10%
90	64.30%	79.00%	1.50%	36.00%
95	67.10%	80.30%	2.70%	42.00%
98	69.70%	81.60%	4.30%	47.40%
100	72.80%	83.10%	9.30%	54.90%

The drawbacks of using mean value consequences in conjunction with 8-hour burn simulations is that it markedly underestimates the true risk present at various locations of SCE's system. SCE has presented a detailed explanation of this in its response to ACI SCE-23-02 in its 2025 WMP Update. Using mean value consequences based on 24-hour simulations, similar to other IOUs, presents higher risk values and may change SCE's current ranking of riskiest areas on its system. SCE is currently considering this methodology. On the one hand, it may capture more extreme events where suppression resources are limited. On the other hand, it also produces more uncertain results. SCE expects to reach a decision on the use of 24-hour simulations by the time its RAMP report is filed in 2026.

Required Progress item #2b: SCE must provide an explanation of how the use of probabilistic distributions impacts its IWMS, including where probability distributions could be integrated into: decision-making, how risk tranches are designated, and how mitigations are selected.

See response above. Use of mean value consequences would impact the current IWMS framework in terms of how much grid hardening SCE would perform and how frequently SCE would inspect certain structures. Under 8-hour burn simulations, this approach would result in fewer mitigations. Under 24-hour burn simulations, this approach would result in more mitigations. However, SCE still continues to use maximum consequences as opposed to mean value consequences. As such, currently there is no impact on SCE's wildfire mitigation strategy.

Required Progress item #2c: Report on the evaluation of additional wildfire simulations and weather scenarios, as described in its 2025 WMP Update.

SCE's new Fire Weather Day (FWD) selection process allows SCE to transition to a quasi-probabilistic model without losing spatial granularity. In its 2025 WMP Update, in response to ACI SCE-23-02 "Calculating Risk Scores Using Maximum Consequence Values in its 2025 WMP Update" SCE stated:

"In 2026-2028 WMP filing, SCE intends to provide additional information for its wildfire simulations so that parties can better understand the historical return interval (e.g., quasi-probabilistic) of the weather scenarios used in its wildfire simulations. This return interval information can be used in conjunction with consequence values to better understand the relative risk of catastrophic wildfires in discrete locations. We will continue to note the potential limitations and weaknesses of using this approach—namely, that even the use of the maximum consequence values may underrepresent the risk at certain locations given that the risk is likely to increase over time."

In its description of Fire Climate Zone (FCZ) specific Fire Behavior Outcomes (FBO) and FWD selection methodology in Section 5.1 and in Section 5.2, SCE describes how the frequency of each of these relevant fire weather conditions are used to develop a quasi-probabilistic distribution of wildfire simulations. Simulations using these FWD produce a distribution of consequences from which percentiles, including mean (as a proxy for expected) values and tail values, can be derived.[214] Recurrence intervals for fire weather conditions can be derived for each FBO in each FCZ.[215] See Appendix B Weather Analysis for a matrix of FBOs comparing the relative contribution of dry fuels and high wind conditions to each FCZ.

Required Progress item #2d: Report on any changes made to SCE's models and associated impacts relating to use of probability distributions as a result of the CPUC's Phase 3 Decision for risk-based decision-making frameworks.

The CPUC's Phase III RDF Decision is not applicable until SCE files its 2026 RAMP. Notably, there are no requirements in that Decision compelling utilities to use probability distributions, and SCE will provide additional information in its 2026 RAMP filing.

Required Progress item #2e: Provide a description of any additional steps SCE is taking to explore the use of probability distributions in the future

SCE continues to use maximum consequence based on *truncated simulation times* as a relevant *tail value*, to prioritize grid hardening activities. We note that this use of maximum consequence based *on truncated simulations times*[216] is distinctly different than using maximum consequence as suggested by this ACI.

Additionally, and as explained in Section 5.2, SCE believes that there is more temporal certainty in 8-hour simulations versus 24-hour simulations,[217] which means that the resulting output of its risk models are not as high as this ACI appears to suggest. These

214 As required by Ordering Paragraph (OP)

215 Recurrence interval = (n + 1)/m, where "n" is the number of years on record and "m" is the rank of observed occurrences when arranged in descending order.

216 D.24-05-064 FoF. 21. "Identifying a truncated power law distribution approach as the best practice to modeling wildfire tail risk while allowing other approaches if submitted and justified in advance provides flexibility and will help address remaining knowledge gaps."

217 D.24-05-064 FoF. 20." There are certain aspects of risk modeling that continue to require refinement, such as properly vetting and comparing results from both 8-hour and 24-hour simulations produced using a commonly used wildfire size distribution model."

certainty values are well documented in a CPUC sponsored report that SCE has referenced in prior WMP filings.[218]

In addition to our response provided in the 2025 WMP Update, SCE believes this is the most pragmatic approach for prioritizing grid hardening activities, given that these values are: 1) based on *actual observed* and relevant fire weather conditions in SCE's service territory; 2) expected to occur again based on the long expected useful life of grid hardening activities; and 3) expected to be a conservative representation of wildfire risk given the likely potential increase in both the frequency of FWDs and consequences due to future climate change, based on State of California data (see Section 3.7 and Section 5.3.2 for additional information). SCE notes that the Phase III Decision explicitly requires that *"[t]he IOUs should seek to avoid, if possible, any long-term asset investment strategy that would be at risk in the future because of climate change impacts*."[219]

SCE will provide any updates to its wildfire risk modeling approach in its 2026 RAMP application, as required. See Section 5.2 for information regarding SCE's quasi-probabilistic approach, including its FWD selection methodology.

218 See depiction of how uncertainty increases over time for wildfire simulation, California Public Utilities Commission 2019 PSPS Event –Wildfire Analysis Report – SCE, specifically pp. 9-10 https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/safety-and-enforcement-division/documents/technosylva-report-on-sce-psps-events-2019.pdf

219 D.24-05-064. Ordering Paragraph *3. (d)*

SCE-23B-04. Incorporation of Extreme Weather Scenarios into Planning Models

Description

SCE currently relies on wind conditions data representing the past 20 years that does not consider rare but foreseeable and significant risks. It does not evaluate the risk of extreme wind events in its service territory to prioritize its wildfire mitigations using MARS and IWMS.

Required Progress

In its 2026-2028 Base WMP, SCE must report on its progress developing statistical estimates of potential wind events over at least the maximum asset life for its system and evaluate results from incorporating these into MARS and IWMS when developing its mitigation initiative portfolio or explain why the approach would not serve as an improvement to its mitigation strategy.

Section and Page Number of Any Improvements: *Sections* 5.1 p. 39, 5.2 p.40 , 5.3 p.109, 5.2.1.5 p. 67 , 5.4 p. 120, 13 p. 484, and Appendix B

SCE Response

SCE Fire Weather Day (FWD) selection methodology—based on its 40+ year historical climatology—includes information regarding both the observed frequency of extreme wind and fuel conditions. FWD is used to calculate risk scores using SCE's MARS framework and to prioritize mitigations using IWMS categories. See Sections 5.1, 5.2, 5.3 and Appendix B Weather Analysis for additional detail.

SCE also notes that the use of extreme wind scenarios further supports SCE's approach in using the potential maximum consequence values of wildfire events.

Wildfire Mitigation Strategy Development

SCE-25U-02. Cross-Utility Collaboration on Best Practices for Inclusion of Climate Change Forecasts in Consequence Modeling, Inclusion of Community Vulnerability in Consequence Modeling, and Utility Vegetation Management for Wildfire Safety

Description

SDG&E, PG&E, and SCE participated in past Energy Safety-sponsored scoping meetings on these topics and began collaborating on other WMP-related topics. However, they have not made substantive efforts to include the other IOUs (Bear Valley, Liberty Utilities, and PacifiCorp).

Required Progress

1. *In its 2026-2028 Base WMP, SCE must continue its collaboration efforts and demonstrate that it has made efforts to include Bear Valley, Liberty Utilities, and PacifiCorp in these efforts where appropriate and relevant to each IOU's interests.*

2. *SCE must also continue to participate in all Energy Safety Safety-organized activities related to best practices for:*

    a. *Inclusion of climate change forecasts in consequence modeling.*

    b. *Inclusion of community vulnerability in consequence modeling.*

    c. *Utility vegetation management for wildfire safety.*

Section and Page Number of Any Improvements: 3.7 p. 22 , 5 p.39

SCE Response

Required Progress item #1: In its 2026-2028 Base WMP, SCE must continue its collaboration efforts and demonstrate that it has made efforts to include Bear Valley, Liberty Utilities, and PacifiCorp in these efforts where appropriate and relevant to each IOU's interests.

SCE collaborates with other utilities, including Bear Valley, Liberty Utilities, PacifiCorp, Xcel Energy, and Hawaii Electric through monthly meetings focusing on Energy Safety activities and other WMP-related topics such as:

- Inspection programs;
- Vegetation management programs;
- Quality Control programs;
- Internal and Contract Resources;
- Remote Sensing Technologies; and
- Optimization of the off-cycle HFTD inspections.

Required Progress item #2: SCE must also continue to participate in all Energy Safety Safety-organized activities related to best practices for: Inclusion of climate change forecasts in consequence modeling; Inclusion of community vulnerability in consequence modeling; Utility vegetation management for wildfire safety.

In addition to meetings driven by Energy Safety, the utilities also collaborate by participating in various industry-related events throughout the year to share best practices and further knowledge on these topics. SCE will continue to participate in all Energy Safety-organized activities related to best practices for inclusion of the topics mentioned in this ACI.

Grid Design, Operations, and Maintenance

SCE-25U-03. Continuation of Grid Hardening Joint Studies

Description

As directed in the 2023-2025 WMP Decisions, the IOUs have made progress on the areas for continued improvement (SCE-22-09, SCE-22-11, and SCE-23-07) relating to the continued joint IOU grid hardening working group efforts. Energy Safety expects the IOUs to continue these efforts and meet the requirements of this ongoing area for continued improvement.

Required Progress

1. *In its 2026-2028 Base WMP, SCE must continue to collaborate with the other IOUs to evaluate various aspects of grid hardening and provide an updated Joint IOU Grid Hardening Working Group Report. This report must include continued analysis for the following:*

    a. *The IOUs' continued joint evaluation of the effectiveness of covered conductor for reducing ignition risk, PSPS risk, and outage risk associated with protective equipment and device settings. This evaluation must include analysis of risk reduction observed in-field as well as research on covered conductor degradation over time and its associated lifetime risk mitigation effectiveness.*

    b. *The IOUs' joint evaluation of the effectiveness of undergrounding for reducing ignition risk, PSPS risk, and outage risk associated with protective equipment and device settings. This evaluation must account for any remaining risk from secondary or service lines and analysis of in-field observations from potential failure points of underground equipment.*

    c. *The IOUs' joint evaluation of lessons learned on undergrounding applications. These lessons learned must include use of resources (including labor and materials) to accommodate undergrounding programs, any new technologies being applied to undergrounding, and cost and associated cost effectiveness efforts for deployment.*

    d. *The IOUs' joint evaluation of various approaches to implementation of protective equipment and device settings. This evaluation must include an analysis of the effectiveness of various settings, lessons learned on how to minimize reliability impacts and safety impacts (including use of downed conductor detection and partial voltage detection devices), variations on settings used by IOUs including thresholds of enablement, and equipment types in which such settings are being adjusted.*

    e. *The IOUs' continued efforts to evaluate new technologies being researched, piloted, and deployed by IOUs. These efforts must include, but not be limited to: REFCL, EFD, distribution fault anticipation (DFA), falling conductor protection, use of smart meter data, open phase detection, remote grids, and microgrids.*

f. *The IOUs' joint evaluation of the overall effectiveness of mitigations in combination with one another, including, but not limited to overhead system hardening, maintenance and replacement, and situational awareness mitigations. This must also include analysis of in-field observed effectiveness, interim risk exposure during implementation, and how those impact effectiveness for ignition risk, PSPS risk, and outage risk associated with protective equipment and device settings.*

g. *Additionally, SCE must report on all lessons learned SCE has applied or expects to apply to its WMP, including a list of applicable changes and a timeline for expected implementation as applicable.*

Section and Page Number of Any Improvements: Section 8.2, p. 222, Table 8-1 p. 219

SCE Response

Please see Appendix F for the Joint IOU report.

SCE-25U-04. Consideration of Prior Actuals in Grid Hardening Targets

Description

SCE reported a decrease to its 2025 covered conductor target due in part to its claimed exceedance of its 2022 covered conductor target. However, SCE should have accounted for the covered conductor miles it installed in 2022 when setting its 2025 target for covered conductor in its 2023- 2025 Base WMP.

Required Progress

1. *In its 2026-2028 Base WMP, SCE must:*

   a. *Explain its process for accounting for its prior years' actuals when setting grid hardening targets, and*

   b. *Demonstrate that it has appropriately accounted for its prior years' actuals, including actuals from 2024, in the grid hardening targets provided in its 2026-2028 Base WMP.*

Section and Page Number of Any Improvements: Section 8.2 p. 222, 13 p. 484, Table 8-1 p. 219

SCE Response

Required Progress item #1a: Explain its process for accounting for its prior years' actuals when setting grid hardening targets.

For its 2026-2028 WMP, SCE has set its foundational grid hardening targets—covered conductor, targeted undergrounding, and REFCL—by considering, where appropriate, the increased difficulty of the "later" units of a mature initiative.

For example, by year-end 2023 SCE had completed approximately 5,500 miles of covered conductor installation in its HFRA. In 2021, 2022, and 2023, SCE exceeded its WMP target for SH-1, sometimes significantly (e.g., 1,500 miles in 2021 relative to a 1,000 mile compliance target). As SCE entered 2024, the remaining scope for covered conductor was a smaller pool of available miles, often with permitting or logistical complications. SCE's prior execution of the program had prioritized high-risk miles with fewer constraints, as this allowed for more rapid risk buy-down in the initial years of wildfire mitigation.

For its 2026-2028 WMP targets for SH-1, SCE undertook a more extensive internal process to develop the specific mile values, considering the above lesson learned that the remaining covered conductor miles typically face more challenges than the miles completed in the 2019-2023 timeframe.

SCE's targeted undergrounding program (SH-2) shares some of the features described above, in that not all miles are equal in terms of project complexity. SCE's earlier SH-2 scope was based on projects in which SCE anticipated lower levels of complexity and potential delays. SCE's forecast in the 2023-2025 WMP reflected this planning approach, with targets of 11, 16, and 30 miles over 2023-2025. However, SCE did not meet the 2023 or 2024 targets for SH-2 due to project complexities including issues related to obtaining the easements and permits necessary for undergrounding previously overhead lines. SCE has reviewed its program scope from a "bottoms-up" perspective to review where projects stand in the engineering and development timeline, with the intention to develop targets that reflect a granular understanding of undergrounding scope and timing.

REFCL projects differ from covered conductor and undergrounding as they do not replace overhead conductor, but instead install equipment at or near the substation, thus protecting an entire circuit (or at least significant portions of it). REFCL projects are not "plug and play" and typically require extensive engineering, equipment, and development unique to each project. SCE's challenges have varied by project, but have involved issues such as lead time for procurement of highly specialized equipment and siting for projects in which equipment is outside of the SCE substation facility. REFCL is still a relatively new technology and thus SCE has installed it at a relatively low number of sites. Accordingly, previous installations do not significantly impact SCE's 2026-2028 REFCL targets (SH-17 and SH-18).

Required Progress item #1b: Demonstrate that it has appropriately accounted for its prior years' actuals, including actuals from 2024, in the grid hardening targets provided in its 2026-2028 Base WMP.

SCE has described its approach above, in response to Required Progress item #1a. SCE considered both 2024 results and 2025 targets in setting the 2026-2028 WMP targets by performing a "bottoms-up" review of scope and progress for each program, with the intention to understand executable scope and timing at a granular level and with the best information available to SCE at the time of its WMP pre-submission in late March 2025.

SCE notes that a three-year forecast cannot have 100% certainty, especially for the outer years of 2027 and 2028. SCE has provided its best effort to submit achievable targets that reflect lessons learned from 2024.

SCE-25U-05. Transmission Conductor Splice Assessment

Description

SCE provided data in its 2025 WMP Update that suggests a high percentage of Priority 1 and 2 splice conditions found by its transmission conductor splice assessment X-rays are not reliably identifiable through other inspection methods. Additionally, SCE did not detail its plan to mitigate the risks associated with its transmission splices.

Required Progress

1. *In its 2026-2028 Base WMP, SCE must provide the following information for each transmission conductor inspection performed in 2023 and 2024:*
    a. *Functional Location (FLOC)*
    b. *Detail (phase and sub conductor)*
    c. *X-ray inspection date*
    d. *Date of most recent aerial inspection prior to X-ray*
    e. *Date of most recent ground inspection prior to X-ray*
    f. *Date of most recent infrared inspection prior to X-ray*
    g. *Circuit*
    h. *Finding issue category*
    i. *Failure mode*
2. *SCE must also discuss its plan to mitigate the risks associated with its transmission splices.*

Section and Page Number of Any Improvements: Section 8.2.6.4 p. 258

SCE Response

Required Progress item #1: In its 2026-2028 Base WMP, SCE must provide the following information for each transmission conductor inspection performed in 2023 and 2024:

a. *Functional Location (FLOC)*
b. *Detail (phase and sub conductor)*
c. *X-ray inspection date*
d. *Date of most recent aerial inspection prior to X-ray*
e. *Date of most recent ground inspection prior to X-ray*

f. Date of most recent infrared inspection prior to X-ray

g. Circuit

h. Finding issue category

i. Failure mode

The requested information for transmission splices inspected in 2023 and 2024 can be found in the SCE 2026 Base WMP Tables - Appendices - SCE-25U-05 tab.

Required Progress item #2: SCE must also discuss its plan to mitigate the risks associated with its transmission splices)

Introduced in the 2022 WMP, Transmission Conductor & Splice Assessment: X-Ray was used on conductor splices to verify proper installation as well as identify broken strands or deformities. Conductors and splices can fail due to age, weather, contact from objects, and other factors leading to wire-downs. To reduce the risk of transmission conductor wire down events, SCE has used enhanced inspection methods, specifically X-ray and LineVue, to identify anomalies and any underlying issues to replace or remediate conductors and/or splices that have a higher probability of failure. In addition, these methods help capture issues that may not be visibly apparent to the human eye or other inspection technologies.

From 2022-2024, the X-Ray inspection program resulted in a total notification rate of 55% with the majority of remediation activity resulting in the shunting of the splice. Due to the find rate based on data collected between 2022-2024, SCE commenced transitioning from the X-ray splice inspection program in 2024 to proactive splice shunting starting in 2025. Instead of inspecting splices via x-ray and then performing remediation, SCE will forego the x-ray inspections and will proactively shunt splices. The transition from inspections to proactive hardening of splices enables SCE to further reduce wildfire risks and enhance the resilience of its transmission infrastructure.

SCE established a Transmission Proactive Splice Shunting Program (SH-20) and set a quantitative target for this program in 2026. Refer to section 8.2.6.4 and Table 8-1 for details on this program. Following the pilot, SCE will use information gathered and lessons learned to inform targets for 2027-2028. This phased approach allows SCE to gather data and adjust the program as needed, ensuring its effectiveness and scalability.

SCE-25U-06. Transmission High Fire Risk-Informed Inspections

Description

SCE reduced its 2025 target for transmission high fire risk- informed (HFRI) inspections from 28,000 to 24,500 due to environmental and access constraints. SCE must improve its response to environmental and access constraints given the impacted assets still present wildfire risk.

Required Progress

In its 2026-2028 Base WMP, SCE must:

1. *Identify the specific access issues impacting its ability to perform transmission HFRI inspections.*
2. *Discuss how SCE is addressing each access issue, including lessons learned, if applicable.*
3. *Provide the number of assets SCE inspected on schedule from 2022 to 2024.*
4. *Provide the number of assets SCE did not inspect on schedule from 2022 to 2024 due to access or environmental constraints.*
5. *Provide the number of assets scheduled for inspection in 2022 and 2023 that SCE did not inspect within one year of the originally scheduled inspection date due to access or environmental constraints.*

Section and Page Number of Any Improvements: *Section* 8.3 p.273, 13 p. 484

SCE Response

Required Progress item #1: Identify the specific access issues impacting its ability to perform transmission HFRI inspections.

SCE inspects its facilities more frequently than required by the relevant CPUC regulations. While SCE has exceeded regulatory requirements, SCE has experienced access and environmental issues impacting its ability to perform certain transmission high fire risk informed (HFRI) inspections. The environmental issues include weather, environmental protection measures, and/or securing agency permits to access inspection sites. The access issues can be grouped into three main categories:

- **Access to property or structure**: Most access constraints are from obtaining permission to access properties or from constraints on customer property, government lands (e.g., lands under jurisdiction of BLM, NPS, and USFS)[220] or

220 Bureau of Land Management (BLM), National Park Service (NPS), United States Forest Service (USFS).

restrictions from lands that are designated as CROPS[221] (Conserve, Reserve, Open Space, and Preserve Sites). A primary constraint is the lack of response from customers or property owners, which necessitates verifying current customer contact information and following an escalation process. In cases where inspectors face hostility or denial of access, SCE engages the appropriate parties, including local law enforcement, to resolve the issue. Additionally, when property owners request SCE's involvement to validate access requests or schedule inspections, SCE engages with the customer to validate requests and schedule the inspection at a convenient time. Government lands and CROPS areas are managed by several local, state, and federal agencies responsible for providing access permission and/or permits, which are required before inspectors can access the property and inspections can be performed. SCE coordinates with each agency to meet varied prerequisites or required deliverables that must be renewed annually before permission or permits are granted to SCE or contract inspection service providers. SCE applies project management practices while working with agencies as each agency has its own timeframe for processing and responding to access requests. In some instances, these permits may take a considerable length of time (up to 3-6 months in some instances) before they are issued, impacting SCE's ability to conduct the inspections needed.

- **Inaccessible roads**: Transmission access roads, which are often graded dirt roads, can experience deterioration and become inaccessible due to weather (heavy or seasonal rains) and traffic impacts resulting from frequent utility inspections and field workers performing PSPS patrols and vegetation management. If the ground is soft due to recent rainfall and a truck is used, the road will immediately degrade, which can create or expand existing ruts. SCE tries to avoid accessing dirt roads within at least 72 hours of a rain event, as it can take up to 7 days for the roads to sufficiently dry. However, there may not always be enough time for the road to completely dry before it needs to be accessed.
- **Obstructions**: These constraints are either customer or vegetation obstructions. When customers or property owners create obstructions, SCE issues a customer clearance notification and ensures the obstruction is resolved before re-releasing the location for inspection. Examples of customer obstruction include installation of a shed, wall, fence or other customer-owned structure immediately adjacent to or attached to an SCE structure, which may create a visual and/or access obstruction that must be cleared before the SCE structure or its attachments can be visually inspected. Vegetation encroaching on SCE structures requires a vegetation trim notification, which is handled by SCE’s Vegetation Management organization.

Other factors including field conditions that prevent safe inspections, such as terrain, weather, or environmental factors, are assessed by SCE to determine if conditions are likely to improve, and direction is provided to the inspector accordingly. Hazards such as

221 SCE term used to refer to agencies/organizations such as The Nature Conservancy, Conejo Open Space Conservation Agency, Laguna Canyon Foundation, and Natural Communities Coalition, etc.

dogs present another challenge, and SCE collects details from the inspector to determine if the hazard can be mitigated. For properties with airspace restrictions, SCE collects details to determine if the constraint can be mitigated. Physical issues like locked gates or required gate codes are addressed by collecting details from the inspector and determining if the constraint can be removed.

Required Progress item #2: Discuss how SCE is addressing each access issue, including lessons learned, if applicable.

SCE has implemented several measures to address the identified access issues. SCE engages with customers and property owners to secure access permissions, validate requests, and schedule inspections at convenient times. Coordination with government and CROPS agencies is also important, as SCE works closely with these agencies to secure necessary permits and prerequisites for inspections. SCE has implemented project management practices to improve coordination with these agencies. Hazard mitigation is another important aspect, with SCE collecting detailed information on hazards and determining if they can be mitigated to allow safe inspections. For unresolved access issues, SCE follows established escalation processes involving internal teams (e.g. Corporate Security), or local law enforcement.

To address the issue of inaccessible roads and enable safe access for inspections, maintenance, capital construction, and emergency work, SCE conducts road grading and vegetation clearing along SCE transmission access roads. Following the historically high precipitation in 2023 and into 2024, SCE undertook significant efforts to repair critically damaged access roads. This effort successfully revitalized more than 750 miles of severely impacted roads, reestablishing vehicle access to over 7,300 structures. Continued maintenance of access roads provides safety advantages such as providing much faster access for first responders during emergencies while serving as fire breaks. In 2026-2028, SCE will continue to maintain and expand its transmission road grading efforts where necessary to contribute to safety and efficiency of SCE operations.

In 2024, SCE convened a team of subject matter experts to evaluate the current challenges associated with constrained inspections and to devise strategies for managing such inspections in 2025 and beyond. Some constraints may be identified prior to field inspections, while others may only become apparent upon attempting access to an SCE structure or during the inspection process itself. The following actions were implemented to manage inspection-related constraints:

- SCE identified all constraint types to enable consistent identification, tracking, monitoring, and resolution of constrained structures to facilitate removal of barriers to completing scheduled inspections.
- A secure geospatial map layer pilot was launched in 2025 to provide Customer Contact Information (CCI) to inspectors, reducing turnaround time for requests, improving efficiency by pre-scheduling property access, and enhancing inspector safety through better public awareness of inspection activities.

- Requirements are being gathered to integrate the CCI map layer with InspectForce (application for performing asset inspections), extending access to all inspectors. A constraint tracker was also developed in 2025 to monitor and resolve constrained inspections and notifications, serving as an interim solution until full integration with InspectForce is achieved.
- SCE is exploring updates to the access constraint escalation process to handle property owner refusals and hostile encounters, ensuring a safe environment for inspections.

Required Progress item #3: Provide the number of assets SCE inspected on schedule from 2022 to 2024.

From 2022 to 2024, SCE met its WMP target for Transmission HFRI inspections. Please refer to the total asset inspection in table SCE D-01.

The table below summarizes the annual target for inspection each year from 2022 to 2024 and the type of inspection performed, as well as assets that experienced access or environmental constraints.

Table SCE D-02: 2022-2024 Transmission HFRI Inspections[222]

Category	**2022**	**2023**	**2024**
Annual WMP Target	16,000	28,000	28,000
Total Asset Inspections	18,035	29,707	32,397
Ground & Aerial Inspection	16,270	27,672	30,040
Ground Only Inspection	902	1,186	1,668
Aerial Only Inspection	863	849	689
Access/Environ Constraint	232	126	33

Required Progress item #4: Provide the number of assets SCE did not inspect on schedule from 2022 to 2024 due to access or environmental constraints.

The number of assets that were in the annual inspection scope but were not inspected due to access or environmental constraints was 232 in 2022, 126 in 2023, and 33 in 2024. SCE works to overcome identified access or environmental constraints as explained in greater detail above.

Required Progress item #5: Provide the number of assets scheduled for inspection in 2022 and 2023 that SCE did not inspect within one year of the originally scheduled inspection date due to access or environmental constraints.

[222] Scope and target for 2023 and 2024 increased due to change in risk methodology. A small subset of assets may be inspected more than once a year based on risk criteria.

SCE reviews its risk-informed inspection scope yearly which impacts the number of assets that remain in scope in subsequent years. The number of assets scheduled for inspection in 2022 and 2023 that SCE did not inspect within one year of the originally scheduled inspection date due to access or environmental constraints was 89 in 2022 and 14 in 2023.

Vegetation Management and Inspections

SCE-23B-16. Implementation of SCE's Consolidated Inspection Strategy, Use of Its Tree Risk Index, and its Satellite-Based Inspection Pilot

Description

SCE is developing these programs and pilot over the course of the 2023-2025 Base WMP cycle. As these programs and pilot mature, Energy Safety will evaluate their quality and execution.

Required Progress

In its 2026-2028 Base WMP, SCE must report on progress, outcomes, and lessons learned related to the development, implementation, and use of its:

1. *Consolidated Inspection Strategy.*
2. *Tree Risk Index.*
3. *Satellite-based inspection pilot.*

Section and Page Number of Any Improvements: *Section* 9 p. 331

SCE Response

Required Progress item #1: Consolidated Inspection Strategy.

Progress: SCE considers this objective implemented. Consolidated inspection practices were implemented by Pre-Inspection (PI) contractors, who are responsible for ensuring consolidated inspections across all three vegetation management programs (i.e. routine line clearances, hazard trees, and dead & dying trees).

Outcomes: The adoption of a consolidated inspection strategy in 2023 and 2024 has improved coordination with environmental review (when feasible), coordination with customers, contractor management, work scheduling, and the bidding process.

Lessons Learned: Pre-inspection contractors new to the Hazard Tree Management Program (HTMP) inspections experienced challenges with onboarding and retaining qualified arborists due to the consolidated inspection strategy. The limited number of qualified arborists in the labor market made this difficult. SCE will continue to evaluate inspection strategies and evaluate contractual adjustments needed to support ongoing consolidated inspection efforts.

Also, vendors were required to adjust work assignments and inspector resources by program due to the complexity of HTMP inspections (which also require ISA certified arborists).

Required Progress item #2: Tree Risk Index.

SCE's Tree Risk Index (TRI) was developed in 2022 and implemented to enhance the management and assessment of tree-related risks. SCE's Tree Risk Index (TRI) methodology is applied for Distribution vegetation management activities and was developed using outputs from SCE's wildfire consequence models, historic Tree Caused Circuit Interruption (TCCI) data, and other VM inventory data. The TRI methodology identifies four risk categories A, B, C & D, with category A being the highest risk.

Progress: SCE continuously looks for opportunities to enhance the TRI's effectiveness. In Q3 2024, TRI was updated with the new Technosylva FireSight 8.0 model, reflecting the latest wildfire consequence data and the IWMS tiers, as well as probability of ignition. The strategy has been actively used in various programs, including routine line clearing[223] and hazard tree management program.

Outcomes: SCE uses a Tree Risk Index (TRI) score to classify grids/circuits within HFRA. In the HTMP program, Category A has annual HTMP inspections, while categories B, C, and D follow a three-year cycle.

In the routine line clearing program, TRI is one of the factors used to prioritize pending remediations.

Lessons Learned: Updates and refinement of some risk assessment processes often have downstream impacts and require updates to other processes. For example, the incorporation of FireSight 8.0 has resulted in growth of the Severe Risk Area (SRA). SCE is exploring adjustment to the TRI based on historical field information to prioritize HTMP work within the SRA.

SCE reviewed the TRI scores for the lower risk categories (B, C, & D) and is considering that for 2026-2028, rather than completing each category in separate sequential years the HTMP scope for B, C & D could be combined and a third of the scope would be executed annually to achieve workflow efficiency until the scope is completed. The scope for TRI category A would continue to be executed annually.

Required Progress item #3: Satellite-based inspection pilot.

In 2023, SCE launched a pilot program to evaluate the use of satellite-based inspections for vegetation management. The initial phase involved one vendor conducting the pilot studies. The goal was to assess the accuracy of satellite data in detecting vegetation encroachments and identifying tree health.

Progress: Overall, the pilot studies have shown that satellite-based inspections can be a valuable tool for vegetation management, particularly in less vegetation dense areas. SCE plans to continue refining the use of this technology and exploring its potential applications in conjunction with other inspection methods. SCE continued the pilot in 2024 and started engaging with additional vendors to determine if they could provide better or comparable results.

[223] SCE refers to the inspections for vegetation clearances from distribution lines (VM-7) and transmission lines (VM-8) as Routine Line Clearing (RLC). Both programs are collectively termed Routine Line Clearing.

Outcomes: The satellite-based inspection pilot yielded promising results. Satellite detection of violation points was 98% accurate with a 2-foot margin of error and 100% accurate with a 3-foot margin of error. The satellite data was 100% accurate in identifying tree health, subject to arborist interpretation of the health status of trees during field validations. Satellite inspection results were able to identify eight specific tree species with an accuracy of approximately 94%.

Lessons Learned: During the 2023 inspections, there were issues with elevation profiles, which were addressed by switching data sources and using pre-existing LIDAR data for validation. In addition, the report formats required for system integration were very particular, necessitating revisions to ensure compatibility with SCE's systems.

Satellite data was found to be less effective during the winter months when trees are in a leaf-off condition. As a result, acquisition efforts were planned to start in April for optimal results.

The pilots demonstrated that satellite data is best suited for low-risk, low-inventory areas (locations with fewer trees and less vegetation). This technology is not yet recommended for high-risk circuits or areas with dense vegetation.

SCE-23B-17. Continuation of Effectiveness of Enhanced Clearances Joint Study

Description

The large IOUs have jointly made progress addressing the Progression of Effectiveness of Enhanced Clearances Joint Study 2022 area for continued improvement (SDGE-22-20, PG&E-22-28, and SCE-22-18). Energy Safety expects the large IOUs and their contracted third party to continue their efforts and meet the requirements of this ongoing area for continued improvement.

Required Progress

With its 2026-2028 Base WMP, SCE, along with PG&E and SDG&E, must attach a white paper that discusses:

1. *The large IOUs' joint evaluation of the effectiveness of enhanced clearances including, but not limited to, the effectiveness of enhanced clearances in reducing tree-caused outages and ignitions.*
2. *The large IOUs' joint recommendations for updates and changes to utility vegetation management operations and best management practices for wildfire safety based on this study. This may include the IOUs' recommendations for updates to regulations related to clearance distances.*

Furthermore, SCE must, as a result of this study and white paper:

3. *Assess the effectiveness of enhanced clearances combined with other mitigations including, but not limited to, covered conductor and protective equipment and device settings (e.g., EPSS, Fast Curve)*
4. *Provide a plan for implementing the results and recommendations of the third-party contractor analysis and the white paper. This plan must include trackable milestones and timelines for implementation. SCE must also provide a list of recommendations it is not implementing and why it is not selecting them for implementation.*

Section and Page Number of Any Improvements: Section 9 p.331, 13 p. 484

SCE Response

Required Progress item #1: The large IOUs' joint evaluation of the effectiveness of enhanced clearances including, but not limited to, the effectiveness of enhanced clearances in reducing tree-caused outages and ignitions.

In partnership with SDG&E and PG&E, SCE collaborated with the Electric Power Research Institute (EPRI) to conduct a "Joint Investor-Owned Utility (IOU) Study on the Effectiveness of Enhanced Vegetation Clearances for Wildfire Management." This study was used to inform a white paper developed by the IOUs, which evaluates the efficacy of enhanced vegetation clearances in reducing tree-related outages and ignitions.

The white paper details the methodology used to create a joint database across the three utilities that includes variables (such as vegetation attributes, weather impacts, and land cover) expected to affect outages and ignitions. It examines the effectiveness of enhanced vegetation management by analyzing outages in high fire threat districts, outages leading to reportable ignitions, and the effect of radial clearance. For instance, the study found that increasing radial clearance led to a reduction in outages caused by vegetation growth and provided evidence that enhanced clearance distances can offer benefits to reduce outages and ignitions. Additionally, the document discusses the role of weather and land cover in influencing the effectiveness of vegetation management enhanced clearances.

Furthermore, the document presents key findings that support the effectiveness of enhanced clearances. It highlights that a low proportion of total outages are caused by vegetation growing into the lines, indicating a direct benefit. The study also shows that enhanced clearance distances led to longer time elapsed between vegetation management activities and subsequent outages, suggesting that maintaining radial clearance at an increased distance reduces the likelihood of outages before the lines are inspected again. These findings are crucial for understanding how enhanced vegetation management can be tailored to reduce tree-caused outages and ignitions effectively.

For further information, refer to the Joint IOU Study of Effectiveness of Enhanced Vegetation Clearances for Wildfire Management. The document can be found in Appendix F of SCE's 2026-2028 WMP.

Required Progress item #2: The large IOUs' joint recommendations for updates and changes to utility vegetation management operations and best management practices for wildfire safety based on this study. This may include the IOUs' recommendations for updates to regulations related to clearance distances.

Different methods were used by the IOUs and EPRI to evaluate the effectiveness of enhanced clearance. All results have shown that greater clearance reduces the probability of outages by a meaningful amount. This reduction in outage frequency consequently results in fewer ignitions. Risk reduction is also affected by factors other than clearance. For example, windy and winter storm weather conditions have different impacts on Northern and Southern California. Data has shown that the effectiveness of enhanced clearance is diminished during and after such conditions.

The following recommendations resulted from the joint IOU study and white paper:

1. Standardizing vegetation management data (e.g., inspection and trim records) would provide additional information about the clearances that are achieved more

broadly for primary overhead circuits and would allow for more robust analyses of clearance effectiveness.

2. Outage investigation reports did not include an estimate of radial clearance at the time of the outage for two of the three IOUs. Adding this estimate to the outage investigation report for all IOUs would provide valuable information to future analyses of clearance effectiveness.
3. Implement a time-series, grid-type analysis. This analysis will leverage weather and landcover data, dividing utility service territories into grid cells for detailed evaluation over time.
4. It is recommended that each IOU make efforts to implement within their data records the ability to associate outage and ignition investigation information as part of their work activity history.
5. Utilities may also additionally benefit from the monitoring of vegetation conditions and clearance by leveraging remote sensing technologies, especially those with larger service territories. By collecting higher frequency data over time utilities may identify patterns in vegetation growth and tree health and measure the minimal clearance based on outage and ignition rates associated with specific circuits or segments to enhance situational awareness.
6. This study recommends identifying locations with historically higher wind gusts and drier fuel conditions to inform of the risk and prioritization of inspection and clearance activities. The strategy should consider location-specific treatments or enhanced clearance practices. Additional mitigation methods should be considered particularly in forest and shrubland areas. Additionally, the establishment of radial clearance at time of pruning should consider multiple factors such as species, growth rate, hazard abatement, industry standards, and tree health.

Required Progress item #3: Assess the effectiveness of enhanced clearances combined with other mitigations including, but not limited to, covered conductor and protective equipment and device settings (e.g., EPSS, Fast Curve)

Covered conductors were installed to mitigate against several risk drivers, including downed power lines, animal contact, vegetation contact, and other interactions with foreign objects. Initial covered conductor testing showed a significant reduction in ignitions from light contact and a minor reduction from heavy tree encounters. The initial testing did not include enhanced clearance data. SCE began deploying covered conductor a little earlier than expanded clearances, thus there is not an abundance of data to separate out the contributions of each mitigation. An analysis could potentially require four different data sets – bare wire without expanded clearances, bare wire with expanded clearances, covered conductor without expanded clearances, and covered conductor with expanded clearances. A sufficient data set could potentially be compiled between the three utilities, however it may take time for the other utilities to deploy sufficient quantities of covered conductor – as stated in the white paper, “Since covered conductor is a relatively recent engineering mitigation measure deployed by the IOUs, additional time will be required to further analyze its effectiveness combined with other mitigation measures." Similarly, SCE deployed Fast Curve settings at a wide scale prior to implementing expanded clearances, which will make it difficult to find sufficient data sets for analysis. Notwithstanding this, going forward SCE will attempt to evaluate the incremental impact of enhanced clearances combined with other mitigations such as covered conductor with available data. SCE anticipates further assessing preliminary findings by the end of 2025, outlining the effectiveness of enhanced clearances combined with covered conductor. Studying enhanced clearances combined with other mitigations such as protective equipment and device settings will be evaluated based on data availability in the future.

Required Progress item #4: Provide a plan for implementing the results and recommendations of the third-party contractor analysis and the white paper. This plan must include trackable milestones and timelines for implementation. SCE must also provide a list of recommendations it is not implementing and why it is not selecting them for implementation.

Table SCE D-03: Plan for Implementation of Recommendations from Third-Party Study and White Paper.

ID	Recommendation	Milestones	Timeline
TP01	Standardizing vegetation management data (e.g., inspection and trim records) would provide additional information about the clearances that are achieved more broadly for primary overhead circuits and would allow for more robust analyses of clearance effectiveness.	Update existing VM-related outage investigation data collection form to require key data elements to improve data analysis.	June 2025
		Rebuild vegetation outage analysis dashboard using recently implemented VM data warehouse (Snowflake)	December 2025
		Integrate outage investigation data into VM work management system (Arbora).	December 2026
TP02	Outage investigation reports did not include an estimate of radial clearance at the time of the outage for two of the three IOUs. Adding this estimate to the outage investigation report for all IOUs would provide valuable information to future analyses of clearance effectiveness.	Update existing outage investigation data collection form to require key data elements to improve data analysis.	June 2025
		Communication/Training to outage investigators	October 2025
TP03	Implement a time-series, grid-type analysis. This analysis will leverage weather and landcover data, dividing utility service territories into grid cells for detailed evaluation over time.	SCE already has fire science and meteorology data that is incorporated into risk analysis, such as with its Areas of Concern (AOC) identification to aid decision making. For identifying AOC, among other items, near term weather such as drought conditions, and vegetation growth based on recent rains in specific locations is taken into consideration.	N/A

ID	Recommendation	Milestones	Timeline
WP01	It is recommended that each IOU make efforts to implement within their data records the ability to associate outage and ignition investigation information as part of their work activity history.	Update existing VM-related outage investigation data collection form to require key data elements to improve data analysis.	June 2025
		Integrate outage investigation data into VM work management system (Arbora).	December 2026
WP02	Utilities may also additionally benefit from the monitoring of vegetation conditions and clearance by leveraging remote sensing technologies, especially those with larger service territories. By collecting higher frequency data over time utilities may identify patterns in vegetation growth and tree health and measure the minimal clearance based on outage and ignition rates associated with specific circuits or segments to enhance situational awareness. This will allow utilities to modify their clearance practices accordingly. Without data collection, opportunities for learning and improvement are reduced.	Publish remote sensing crown polygons into work management system for inspection activities	December 2025
		Expand baseline network digital twin model	June 2026
		Reduce ground-based inspections. (ongoing - subject to adjustment based on technological constraints and operational needs).	2026-2028
WP03	This study recommends identifying locations with historically higher wind gusts and drier fuel conditions to inform of the risk and prioritization of	SCE already has a Severe Risk Area layer which encompasses PSPS high wind areas, egress/ingress, acreage impacted, and communities of elevated fire concern. This layer helps determine	N/A

ID	Recommendation	Milestones	Timeline
	inspection and clearance activities. The strategy should consider location-specific treatments or enhanced clearance practices. Additional mitigation methods should be considered particularly in forest and shrubland areas. Additionally, the establishment of radial clearance at time of pruning should consider multiple factors such as species, growth rate, hazard abatement, industry standards, and tree health.	remediation prioritization for routine line clearing, and inspection cadences based on tree risk index for hazard tree mitigations. In addition, as part of AOC seasonal patrols, SCE factors historical wind gusts and areas with drier fuel conditions as part of the considerations for identifying AOCs.	

Community Outreach and Engagement

SCE-23B-21. Community Outreach 3- and 10-Year Objectives – Verification Methods

Description

SCE's verification methods for some of its community outreach objectives are vague and do not readily demonstrate what specifically will be used to verify progress on and achievement of the objective.

Required Progress

In its 2026-2028 Base WMP, SCE must include all methods used to verify progress on objectives within the tables describing its 3-year and 10-year community outreach objectives. SCE must articulate its verification methods to demonstrate the effectiveness in verifying progress on, and achievement of, each objective.

Section and Page Number of Any Improvements: Section 3.2 p. 8, 11.3 p. 445 , 11.4 p. 456 *and* Table 11-1 p. 433

SCE Response

Required Progress item: In its 2026-2028 Base WMP, SCE must include all methods used to verify progress on objectives within the tables describing its 3-year and 10-year community outreach objectives. SCE must articulate its verification methods to demonstrate the effectiveness in verifying progress on, and achievement of, each objective.

The 2026-2028 WMP Guidelines no longer include 3-year and 10-year objectives.[224] The 10-year objectives have been eliminated, while 3-year objectives are now defined as qualitative targets.

Consistent with this guidance, SCE's WMP includes qualitative targets in Table 11-1 with verification methods to track progress towards and achievement of Community Outreach and Engagement objectives:

- Wildfire Safety Community Meetings (DEP-1) will document the content and attendance of wildfire community safety meetings held.[225]
- Customer Research and Education (DEP-4) will document any results of customer studies pertaining to both wildfire mitigation and PSPS.[226]
- Critical Care Backup Battery Program (PSPS-2) will document battery deliveries to eligible customers and the time taken to deliver backup batteries after program enrollment.[227]
- Portable Power Station and Generator Rebates (PSPS-3) will document how many rebate claims are processed and the time taken to process rebates after receipt of all customer information from SCE's website vendor.

SCE will also track progress towards community outreach and engagement through its performance metrics by measuring the percentage of customer recall of SCE wildfire and preparedness communications, both across its entire system (performance metric 11a) and specifically for customers in its HFRA (performance metric 11b).[228]

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[224] Available Materials for Package 1 Draft WMP Guidelines Workshop, Draft Wildfire Mitigation Plan Guidelines Public Workshop for Package 1 Materials, November 26, 2024, p. 28: "No longer requiring 10-year targets; focus on one- and three-year targets within the three-year cycle."
[225] See SCE 2026-2028 WMP Table 11-1 and Section 11.4 Public Communication, Outreach, and Education Awareness
[226] See SCE 2026-2028 WMP Table 11-1 and 11.3 External Collaboration and Coordination
[227] See SCE 2026-2028 WMP 11.5 Customer Support in Wildfire and PSPS Emergencies
[228] See SCE 2026-2028 WMP Section 3.5 Performance Metrics

Public Safety Power Shutoffs

SCE-23B-22. Consideration of PSPS Damage in Consequence Modeling

Description

SCE is in the early stages of improving its modeling methodology and has not fully evaluated whether and/or how PSPS event damage information is considered in PSPS decision-making.

Required Progress

In its 2026-2028 Base WMP, SCE must report on progress it has made in incorporating observed PSPS event damage information into its PSPS consequence modeling. If SCE has come to a conclusion on whether and/or how PSPS event damage information is considered in its PSPS decision making by its 2026-2028 Base WMP submission, SCE must include an explanation of findings that led to the conclusion.

Section and Page Number of Any Improvements: Section 7 p. 208 and 13 p. 479

SCE Response

SCE is examining how PSPS event damages could play a role in operational PSPS decision making, such as windspeed de-energization thresholds.[229] In 2024, SCE collected and analyzed PSPS event damage information when exploring the development of a predictive, data-driven PSPS windspeed threshold model that considers a wide variety of asset, operations, and equipment failure data. SCE reviewed data on conductor and pole damage, for example, as key inputs into the model. The goal of this effort was to prototype and test an enhanced methodology that would update PSPS wind speed thresholds based on the probability of a wind-caused fault/outage at the circuit segment level. However, the prototype did not produce satisfactory results due primarily to machine learning model accuracy concerns. SCE is looking into alternative approaches to refine and simplify its existing PSPS threshold methodology.

At this point, SCE is still evaluating whether and, if so, how to incorporate PSPS event damage information into its operational PSPS decision making. SCE is planning to conduct an internal review of its PSPS threshold methodologies during the 2026-2028 WMP period.

[229] To clarify, observed PSPS event damages should not play a role in how PSPS consequences are calculated. Observed damages such as vegetation contact with a line may indicate where an ignition could have occurred. However, this does not change PSPS consequence modeling, which forecasts the potential scope and scale of negative impacts to customers from a PSPS de-energization event.

Appendix E: Referenced Regulations, Codes, and Standards

In this appendix, the electrical corporation must provide in tabulated format a list of referenced codes, regulations, and standards.

SCE provides a checklist of the statutory requirements below.

Name of Regulation, Code, or Standard	Brief Description
14 C.F.R. § 107, et seq.	FAA certification for Unmanned Aircraft Systems & pilots
14 C.F.R. § 133, et seq.	Rotorcraft External-Load Operations
14 C.F.R. § 61, et seq.	FAA Certification: Pilots, Flight Instructors, and Ground Instructors
14 C.F.R. § 91, et seq.	General Operating and Flight Rules
16 U.S.C. § 1362 et seq. (Marine Mammal Protection Act (MMPA)	Protects endangered marine mammals
16 U.S.C. § 1451 et seq. (Federal Coastal Zone Management Act)	Bureau of Ocean Energy Management- protection, management, and development of the coastal zone
16 U.S.C. § 1451 et seq. (Federal Coastal Zone Management Act)	Protect the coastal environment from growing demands associated with residential, recreational, commercial, and industrial uses
16 U.S.C. § 668 et seq.(Bald and Golden Eagle Protection Act (BGEPA)	Prohibits anyone from "taking" bald or golden eagles, including their parts, including feathers, nests, or eggs.

Name of Regulation, Code, or Standard	Brief Description
16 U.S.C. § 703 et seq. (Migratory Bird Treaty Act (MBTA))	Outlaws the taking, killing, or possessing migratory birds.
16 U.S.C. §§ 1531-1544 (Federal Endangered Species Act of 1973(ESA))	Provide a means whereby the ecosystems upon which endangered species and threatened species may be conserved.
16 U.S.C. §§ 470aa–470mm (Archaeological Resources Protection Act (ARPA)	Protection of archaeological resources and sites which are on public lands and Indian lands.
16 U.S.C. §§ 470aaa-470aaa-11 (Paleontological Resources Preservation Act (PRPA)	Provides specific mandates for administering paleontological resource research and collecting permits and the curation of fossil specimens in museum collections.
25 U.S.C. § 3001 et seq. (Native American Graves Repatriation Protection Act (NAGRPA)	Gives rights of Indian tribes to obtain repatriation of human remains, funerary objects, sacred objects, and objects of cultural patrimony from federal agencies and museums.
33 U.S.C. §§ 1251-1388 (Federal Clean Water Act (CWA)	Establishes the basic structure for regulating discharges of pollutants into the waters of the United States and regulating quality standards for surface waters.

Name of Regulation, Code, or Standard	Brief Description
42 U.S.C § 4321 et seq. (National Environmental Policy Act (NEPA)	Policy to encourage harmony between man and his environment; promote efforts to prevent or eliminate damage to the environment; stimulate health and welfare of man; enrich understanding of ecological systems and natural resources; and to establish a Council on Environmental Quality.
54 U.S.C. §§ 300101-307108 (National Historic Preservation Act (NHPA)	Preservation policy for historic property.
54 U.S.C.§§ 320301-320303 (Antiquities Act of 1906)	provide general legal protection of cultural and natural resources of historic or scientific interest on Federal lands.
A.22-05-013	Risk Assessment Mitigation Phase Proceeding (RAMP).
AB 1054 (2019)	Rules for reviewing and setting of HFTD boundaries every year.
AB 2911 (2018)	Identification of fire districts without a secondary egress route that are at significant fire risk.

Name of Regulation, Code, or Standard	Brief Description
AB 52 (2014)	California Assembly bill requiring that a project with an effect that may cause a substantial adverse change in the significance of a tribal cultural resource and requires consultation with Native American under CEQA.
California Code of Regulations, Title 13, §§ 2450 - 2465	Portable Equipment Registration Program (PERP) and Portable Engine Airborne Toxic Control Measure.
California Code of Regulations, Title 14, § 15268(d)	Definition of “ministerial projects”
California Code of Regulations, Title 14, § 15381	Definition of “responsible agency”
California Code of Regulations, Title 14, §§ 1250 - 1258	Provide specific exemptions from: electric pole and tower firebreak clearance standards, electric conductor clearance standards and to specify when and where the standards apply.
California Environmental Quality Act (CEQA)	Requires public agencies to “look before they leap” and consider the environmental consequences of their discretionary actions.

Name of Regulation, Code, or Standard	Brief Description
California Fish and Game Code §§ 1600 - 1616	Protection and conservation of the fish and wildlife resources in lakes and streams.
California Fish and Game Code § 2050 et seq. (California Endangered Species Act (CESA))	Legislation to conserve, protect, restore, and enhance any endangered species or any threatened species and its habitat.
California Fish and Game Code § 2080 et seq.	California Endangered Species Act - prohibition of trading endangered or threatened species.
California Fish and Game Code § 3503	Prohibits destruction of bird nests and eggs.
California Fish and Game Code § 3503.5	Prohibits possession or destruction of birds-of-prey.
California Fish and Game Code § 3511	Prohibits possession of fully protected birds without a license.
California Fish and Game Code § 3513	Prohibits possession of migratory nongame bird as designated in the Federal Migratory Bird Treaty Act (16 U.S.C. Sec. 703 et seq.).
California Fish and Game Code § 3800	Definition of nongame birds and mining regulation affecting same.
California Fish and Game Code § 4700	Definition of fully protected mammals.
California Fish and Game Code § 5050	Protection of reptiles and amphibians.

Name of Regulation, Code, or Standard	Brief Description
California Fish and Game Code § 5515	Definition of fully protected fish and possession prohibition.
California Fish and Game Code §§ 1900-1913 (Native Plant Protection Act)	Preservation, protection and enhancement of endangered or rare native plants of California.
California Fish and Game Code §§ 5650 - 5652	Prohibit the deposition, passage of, or disposal of deleterious materials into the waters of the state, or within 150 feet of the highwater mark of waters of the state.
California Food and Agriculture Code §§ 80001-80201 (California Desert Native Plants Act)	Protection of native plants from unlawful harvesting on both public and privately owned lands.
California Government Code § 8593.3(f)(1)	Definition of access and functional population.
California Health and Safety Code §§ 39000 - 44474	Protection of ambient air quality, control, and maintenance.
California Public Resources Code § 21069	Definition of "responsible agency," "ministerial projects" and the Endangered Species Act.
California Public Resources Code § 21080.3.2	California Environmental Quality Act permits mitigation measures capable of lessening impacts to a tribal cultural resource.

Name of Regulation, Code, or Standard	Brief Description
California Public Resources Code § 30000, et seq. (California Coastal Act)	California Coastal Commission rules including delegation of Local Coastal Programs (LCPs) to cities and counties and guides how the land along the coast of California is developed or protected from development.
California Public Resources Code § 4290.5	Identification of fire districts without a secondary egress route that are at significant fire risk.
California Public Resources Code § 4291	Defensible space requirement for land covered in flammable material.
California Public Resources Code § 4292	Clearance requirements around structures.
California Public Resources Code § 4293	Statute requires utilities to maintain a clearance of the respective distances which are specified in this section in all directions between all vegetation and all conductors which are carrying electric current; Mitigation requirement of hazards posed by dead trees or significantly compromised and maintenance of clearance of the respective distances from power lines.

Name of Regulation, Code, or Standard	Brief Description
California Public Utilities Code § 326(a)(2)	Meaning of “maximum feasible”
California Public Utilities Code § 8386(a)	Electrical corporation’s duty to minimize catastrophic wildfires
California Water Code § 13000, et seq. (California Porter-Cologne Water Quality Control Act)	Conservation, control, and utilization of the water resources of the state, and quality protection. Water Quality Control Board including multiple Regional Water Quality Control Boards
D.12-01-032	Decision adopting regulations to reduce fire hazards associated with overhead power lines and communication facilities; and decision approving the work plan for the development of fire map 1
D.12-04-024	Decision re Electric Investor-Owned Utilities reporting requirements for Resolution ESRB-8 Extending De-Energization Reasonableness, Notification, Mitigation.

Name of Regulation, Code, or Standard	Brief Description
D.14-01-010	Decision adopting regulations to reduce fire hazards associated with overhead power lines and communication facilities; and decision approving the work plan for the development of fire map 1.
D.15-05-006	Decision modifying HFTD boundaries in SCE's territory.
D.17-12-024	Decision adopting regulations to enhance fire safety in the HFTD.
D.18-12-014	Adoption of 2018 Safety Model Assessment Proceeding (S-MAP)
D.19-05-042	PSPS Order Instituting Rulemaking (OIR) Phase 1
D.20-05-051	PSPS Order Instituting Rulemaking (OIR) Phase 2
D.20-05-051	Implementation of pilot projects to investigate the feasibility of mobile EV Level 3 fast charging for areas impacted by PSPS events.

Name of Regulation, Code, or Standard	Brief Description
D.20-05-051	Decision sets quarterly meetings to provide updates on PSPS enhancement efforts and solicit input for improvement areas in how SCE approaches PSPS overall and provides a forum for stakeholders to propose ways to improve all aspects of PSPS
D.20-08-046	Climate Adaptation Vulnerability Assessment: utilities to study climate risks to their assets, operations, and services and to file the assessment results one year before their GRC to enable the results of the assessment to inform GRC requests
D.20-12-030	Decision modifying the high fire-threat district boundaries in SCE service territory
D.21-06-014	PSPS Order Instituting Investigation
D.21-06-034	PSPS Order Instituting Rulemaking (OIR) Phase 3
GO 128	Rules for construction of underground electric supply and communication systems.

Name of Regulation, Code, or Standard	Brief Description
GO 165	Inspection Requirements for Electric Distribution and Transmission Facilities
GO 166	Standards for Operation, Reliability, and Safety during Emergencies and Disasters
GO 167-B	Enforcement of Maintenance and Operation Standards for Electric Generating Facilities.
GO 174	Rules for Electric Utility Substations, governing standards for substation inspection and management
GO 95	Public Utilities Commission Rules for Overhead Electric Line Construction
GO 95 Rule 37	Minimum Clearances of Wires above Railroads, Thoroughfares, Buildings, Etc.
GO 95, Appendix E	Specifies increased time-of-trim clearances between bare-line conductors and vegetation.
GO 95, Rule 18	Prioritization of maintenance utilizing a three-tier priority maintenance system

Name of Regulation, Code, or Standard	Brief Description
GO 95, Rule 18A	Requires electric utilities to place a high priority on the correction of significant fire hazards.
GO 95, Rule 22.8-A, 22.8-B, 22.8-Cor22.8-D	Meaning of "Protective Covering, Suitable" and minimum standards for ground/bond wire, supply conductor, bolt covers, insulated flexible conduit
GO 95, Rule 31.1	Design, Construction and Maintenance of overhead lines
GO 95, Rule 35	Mitigation requirement of hazards posed by dead trees or significantly compromised. Mandate for removal of dead trees that overhang or lean toward a supply line; Mandates vegetation management to prevent encroachment into Clearance Zones
GO 95, Rule 35 Appendix E	Order specifies vegetation management expanded clearances, Grid Resiliency Clearance Distance (GRCD)
GO 95, Rule 35, Table 1, Case 14	Order requires increased radial clearances between bare-line conductors and vegetation in high fire-threat areas of Southern California.
GO 95, Rule 44.2	Order requires ad hoc inspections through IPI program.

Name of Regulation, Code, or Standard	Brief Description
GO 95, Rules 31.2, 80.1A and 90.1B	Order sets the minimum frequency for inspections of aerial communication facilities located in close proximity to power lines.
GO 95, Sections V, VI, VII, VIII, X & XI	Order governs the height of Electrical Equipment in the Service Territory
I.14-03-004	Order Instituting Investigation on the Commission's Own Motion into the Operations and Practices of SCE Regarding the Acacia Avenue Triple Electrocution Incident in San Bernardino County and the Windstorm of 2011
Material Specifications 454	SCE's inspection and treatment of wood poles in service. Details on how to do intrusive inspection and the criteria for passing/failing of poles
R.08-11-005	Decision adopting regulations to reduce fire hazards associated with overhead power lines and communication facilities; and decision approving the work plan for the development of fire map 1

Name of Regulation, Code, or Standard	Brief Description
R.08-11-005	Order Instituting Rulemaking to Revise and Clarify Commission Regulations Relating to the Safety of Electric Utility and Communications Infrastructure Provider Facilities.
R.15-05-006	Order Instituting Rulemaking to Develop and Adopt Fire-Threat Maps and Fire-Safety Regulations.
R.18-04-019	Order Instituting Rulemaking to Consider Strategies and Guidance for Climate Change Adaptation
R.19-09-009	Order Instituting Rulemaking Regarding Microgrids Pursuant to Senate Bill 1339 and Resiliency Strategies
R.20-07-013	CPUC Order Instituting Rulemaking to Further Develop a Risk-Based Decision-Making Framework for Electric and Gas Utilities
R.20-07-013	Order Instituting Rulemaking to Further Develop a Risk-Based Decision-Making Framework for Electric and Gas Utilities

Name of Regulation, Code, or Standard	Brief Description
Resolution ESRB-4	Mitigation requirement of hazards posed by dead trees or significantly compromised. Directs Investor-Owned Electric Utilities to take remedial measures to reduce the likelihood of fires started by or threatening utility facilities.
Resolution ESRB-8	Resolution Extending De-Energization Reasonableness, Notification, Mitigation, and Reporting Requirements in Decision 12-04-024 to All Electric Investor-Owned Utilities
Resolution SED-5 and SED-5A	Resolution approving administrative consent order and agreement of the Safety and Enforcement Division and SCE regarding the 2017/2018 Southern California fires pursuant to Resolution M-4846
SB 901 (2018)	Senate bill requiring IOUs to file Wildfire Mitigation Plans.
Substation Construction and Maintenance; Maintenance and Inspection Manual	Policies and procedures for substation inspections and maintenance
System Operating Bulletin 21	System Emergency Response Plan
System Operating Bulletin 322	SCE's Standard Operating Bulletin criteria for FCZ, FWT, HFRA, PSPS & TT

Name of Regulation, Code, or Standard	Brief Description
Various Encroachment Permits	Permitting governed by CA Dept. of Transportation, CA Dept. Water Resources

Appendix F

F1 – Continuation of Section 4.3 Frequently Deenergized Circuits

Table 4-3: SCE Frequently Deenergized Circuits

[1] Pursuant to the guidance, SCE has only included circuits that experienced three or more deenergizations in a year for the 6 years prior to the submission of this WMP. Such circuits are not included in years in which they only experienced two or fewer deenergizations.

[2] For Date of Outage, SCE provides the de-energization date. For the dates listed, multiple deenergizations may have occurred on the same date.

[3] For Customer Hours of PSPS per Outage per Circuit, SCE calculates by isolation device or segments the difference between restoration time and deenergization time in hours multiplied by the total number of customers impacted, summed for each circuit. PSPS tracking and reporting varied until 2021. As such, SCE was not able to produce comparable values of customer hours of PSPS per outage per circuit for 2019, 2020, or 2021.

[4] SCE lists here measures taken or planned to reduce PSPS impacts. This might not include all wildfire mitigations on a circuit, as some measures are taken or planned to reduce wildfire risk. For example, there may be more covered conductor, REFCL, or other system hardening performed on each circuit than listed in this table.

Entry #	Circuit ID [1]	Name of Circuit	Dates of Outages [2]	Number of Customers Hours of PSPS per Outage [3]	Measures taken, or planned to be taken, to reduce the need for, and impact of, future PSPS of circuit [4]	Estimated Annual Decline in PSPS Events and PSPS Impact on Customers
1	ED-00108	ACOSTA	12/3/2020 11/27/2020 10/26/2020 10/30/2019 10/28/2019 10/24/2019 10/10/2019	Data not available	Completed: • Automated 1 existing switch • Implemented operational protocol to raise PSPS windspeed thresholds • Replaced 7.28 miles of existing overhead wire with new insulated wire	This section requests electrical corporations to provide projections for future deenergizations and customer impacts. PSPS are a function of future weather conditions and cannot be predicted with a meaningful level of certainty. Between 2023 and 2025, SCE's service territory saw more extreme fire weather with each subsequent year prompting an annual increase in PSPS. If in future years current trends of extreme weather and fire conditions continue, PSPS events will continue and may increase in frequency and duration as an essential mitigation to protect public safety.
2	ED-00452	AMETHYST	12/8/2020 12/3/2020 11/27/2020 10/26/2020	Data not available	Completed: • Replaced 1.4 miles of existing overhead wire with new insulated wire • Installed an additional weather station to improve situational awareness	
3	ED-00560	ANGUS	11/25/2021 11/25/2021 11/25/2021 1/19/2021	Data not available	Completed: • Replaced 5.66 miles of existing overhead wire with new insulated wire	
			12/10/2024	583	Completed: • Replaced 27.17 miles of existing overhead wire with new insulated wire • Installed an additional weather station • Installed 1 automated switch and implemented additional segmentation • Implemented operational protocol to raise PSPS windspeed thresholds Planned Work:	
			12/9/2024	1,926		
			11/6/2024	3,304		
			12/9/2023	1,328		
			10/30/2023	578		
			10/29/2023	395		
			11/25/2021			

Entry #	Circuit ID [1]	Name of Circuit	Dates of Outages [2]	Number of Customers Hours of PSPS per Outage [3]	Measures taken, or planned to be taken, to reduce the need for, and impact of, future PSPS of circuit [4]	Estimated Annual Decline in PSPS Events and PSPS Impact on Customers
4	ED-01344	ANTON	11/25/2021 11/25/2021 1/19/2021 1/19/2021 1/19/2021 1/17/2021 1/15/2021 12/23/2020 12/19/2020 12/19/2020 12/7/2020 12/7/2020 12/3/2020 11/26/2020 10/26/2020 10/26/2020 10/16/2020 9/9/2020 11/17/2019 10/30/2019 10/28/2019 10/24/2019 10/10/2019	Data not available	• Install 1 automated switch and implement additional segmentation	
5	ED-00705	ARLENE	12/23/2020 12/7/2020 12/3/2020 11/26/2020	Data not available	Completed: • Replaced 9.04 miles of existing overhead wire with new insulated wire • Updated switching protocols	
6	ED-00817	ATENTO	12/24/2020 12/3/2020 11/27/2020 10/26/2020	Data not available	Completed: • Replaced 38.34 miles of existing overhead wire with new insulated wire • Implemented operational protocols to raise PSPS windspeed thresholds • Installed 3 automated switches and implement additional segmentation	
7	ED-00971	BADGER	11/25/2021 11/21/2021 1/19/2021	Data not available	Completed: • Replaced 1.6 miles of existing overhead wire with new insulated wire Planned Work: • Replace 1.45 miles of existing overhead wire with new insulated wire	
			12/10/2024	130	Completed:	

Entry #	Circuit ID [1]	Name of Circuit	Dates of Outages [2]	Number of Customers Hours of PSPS per Outage [3]	Measures taken, or planned to be taken, to reduce the need for, and impact of, future PSPS of circuit [4]	Estimated Annual Decline in PSPS Events and PSPS Impact on Customers
8	ED-00990	BALCOM	11/6/2024 11/6/2024 12/23/2020 12/7/2020 12/3/2020 10/30/2019 10/28/2019 10/24/2019 10/10/2019	12,583 1,201 Data not available	• Replaced 13.86 miles of existing overhead wire with new insulated wire • Implemented switching protocols to transfer load to a less affected circuit • Installed an additional weather station	
9	ED-01630	BIG ROCK	11/25/2021 1/19/2021 1/15/2021 1/14/2021 12/23/2020 12/7/2020 12/7/2020 12/3/2020 12/3/2020 11/27/2020 11/26/2020 10/26/2020	Data not available	Completed: • Replaced 10.69 miles of existing overhead wire with new insulated wire • Installed 2 automated switches • Installed an additional weather station • Implemented operational and switching protocols to transfer load to a less affected circuit	
10	ED-03314	BIRCHIM	11/22/2024 10/28/2024 10/27/2024 10/17/2024 8/24/2024	6,683 1,355 115 11,654 21	Under engineering review for PSPS grid hardening measures	
11	ED-01745	BLACKHILLS	11/24/2021 1/19/2021 1/15/2021	Data not available	Completed: • Replaced 0.68 miles of existing overhead wire with new insulated wire Planned Work: • Replace 0.05 miles of existing overhead wire with new insulated wire	
			12/9/2024 11/6/2024 10/18/2024	812 471 8,600	Under engineering review for PSPS grid hardening measures Completed:	

Entry #	Circuit ID [1]	Name of Circuit	Dates of Outages [2]	Number of Customers Hours of PSPS per Outage [3]	Measures taken, or planned to be taken, to reduce the need for, and impact of, future PSPS of circuit [4]	Estimated Annual Decline in PSPS Events and PSPS Impact on Customers
12	ED-01832	BLUE CUT	12/3/2020 11/27/2020 10/26/2020	Data not available	• Replaced 40.43 miles of existing overhead wire with new insulated wire Planned Work: • Replace 10.51 miles of existing overhead wire with new insulated wire	
13	ED-01954	BOOTLEGGER	12/23/2020 12/7/2020 12/3/2020 11/27/2020 10/26/2020 9/9/2020	Data not available	Completed: • Insulated Wires: Replaced 28.82 miles of existing overhead wire with new insulated wire • Implemented switching protocol to remove some customers and critical businesses from PSPS	
14	ED-02035	BOUQUET	10/30/2019 10/24/2019 10/10/2019	Data not available	Completed: • Replaced 30.23 miles of existing overhead wire with new insulated wire • Added temporary generator to serve approx. 250 customers during a PSPS event with minimal outages	
15	ED-02191	BRENNAN	12/9/2023 11/20/2023 10/29/2023	9,991 1,851 5,566	Under engineering review for additional covered conductor scope	
16	ED-02261	BROADCAST	12/18/2024 12/9/2024 11/6/2024 10/18/2024	286 736 3,759 493	Under engineering review for potential remote grid / PSPS grid hardening measures	
17	ED-02577	CABANA	11/24/2021 1/19/2021 1/15/2021	Data not available	Completed: • Replaced 0.6 miles of existing overhead wire with new insulated wire	
18	ED-02674	CALGROVE	12/17/2024 12/9/2024 11/6/2024 11/25/2021 1/19/2021 1/16/2021 1/15/2021	125 182 24,087 Data not available	Under engineering review for PSPS grid hardening measures Completed: • Replaced 5.67 miles of existing overhead wire with new insulated wire • Installed 1 automated switch • Installed an additional weather station	
			12/17/2024	219	Under engineering review for PSPS grid hardening measures	

Entry #	Circuit ID [1]	Name of Circuit	Dates of Outages [2]	Number of Customers Hours of PSPS per Outage [3]	Measures taken, or planned to be taken, to reduce the need for, and impact of, future PSPS of circuit [4]	Estimated Annual Decline in PSPS Events and PSPS Impact on Customers
19	ED-02751	CALSTATE	12/10/2024	248	Completed: • Replaced 3.04 miles of existing overhead wire with new insulated wire Planned Work: • Install 1 automated switch	
			11/6/2024	535		
			12/9/2023	221		
			10/30/2023	160		
			10/29/2023	219		
			11/25/2021	Data not available		
			11/21/2021			
			1/19/2021			
			1/15/2021			
			12/23/2020			
			12/8/2020			
			12/3/2020			
			11/27/2020			
			10/26/2020			
			10/30/2019			
			10/30/2019			
			10/28/2019			
			10/24/2019			
			10/20/2019			
			10/10/2019			
20	ED-02790	CAMP BALDY	12/8/2020	Data not available	Completed: • Installed insulated wire	
			11/27/2020			
			10/26/2020			
21	ED-03099	CASMALIA	10/30/2019	Data not available	Completed: • All existing overhead in HFRA was previously switched to the Impala 12kV	
			10/28/2019			
			10/24/2019			
			10/10/2019			
22	ED-04632	CASTRO	11/25/2021	Data not available	Completed: • Replaced 18.73 miles of existing overhead wire with new insulated wire • Installed 2 automated switches • Installed an additional weather station • Added a new switch to improve segmentation and reduce customer impacts	
			11/21/2021			
			1/19/2021			
			12/24/2020			
			12/7/2020			
			12/3/2020			
			10/30/2019			
			10/28/2019			
			10/24/2019			
			10/11/2019			
			12/23/2020		Completed:	

Entry #	Circuit ID [1]	Name of Circuit	Dates of Outages [2]	Number of Customers Hours of PSPS per Outage [3]	Measures taken, or planned to be taken, to reduce the need for, and impact of, future PSPS of circuit [4]	Estimated Annual Decline in PSPS Events and PSPS Impact on Customers
23	ED-03714	COBRA	12/7/2020 12/3/2020	Data not available	• Replaced 0.24 miles of existing overhead wire with new insulated wire • Automated 2 existing switches • Installed an additional weather station	
24	ED-03885	CONDOR	1/19/2021 1/19/2021 1/19/2021 12/23/2020 12/8/2020 12/7/2020 12/7/2020 12/3/2020 11/27/2020 11/27/2020 10/30/2019 10/24/2019 10/10/2019	Data not available	Completed: • New insulated wire has already been installed on nearly all existing overhead portions of the circuit • Replaced an additional 1.7 miles of existing overhead wire with new insulated wire near the substation	
25	ED-04109	CORSAIR	11/25/2021 1/19/2021	Data not available	Completed: • Replaced 70.82 miles of existing overhead wire with new insulated wire	
26	ED-04495	CUDDEBACK	12/3/2020 12/2/2020 11/16/2020 10/30/2019 10/28/2019 10/24/2019 10/10/2019	Data not available	Completed: • Replaced 7.53 miles of existing overhead wire with new insulated wire	
27	ED-04526	CUTHBERT	12/9/2024	96270	Under engineering review for PSPS grid hardening measures (covered conductor and undergrounding) Completed: • Installed 1 automated switch • Replaced 2.02 miles of existing overhead wire with new insulated wire • Implemented operational protocols to raise PSPS windspeed thresholds, and transfer load to a less affected circuit	
			11/6/2024	85942		
			10/18/2024	56731		
			11/25/2021 11/25/2021 11/21/2021 1/19/2021 1/15/2021	Data not available		
			12/9/2024	13,344	Under engineering review for PSPS grid hardening	

Entry #	Circuit ID [1]	Name of Circuit	Dates of Outages [2]	Number of Customers Hours of PSPS per Outage [3]	Measures taken, or planned to be taken, to reduce the need for, and impact of, future PSPS of circuit [4]	Estimated Annual Decline in PSPS Events and PSPS Impact on Customers
28	ED-04596	DALBA	11/6/2024 10/18/2024	13,795 17,428	measures	
29	ED-04706	DAVENPORT	12/10/2024 12/10/2024 11/6/2024	20,265 10,431 5,674	Completed: • Replaced 41.72 miles of existing overhead wire with new insulated wire	
			1/19/2021 1/19/2021 1/15/2021 1/15/2021 12/7/2020 12/7/2020 12/7/2020 12/3/2020 11/27/2020 11/26/2020 10/26/2020 10/26/2020 10/30/2019 10/28/2019 10/24/2019 10/10/2019	Data not available		
30	ED-04900	DE MILLE	12/8/2020 12/3/2020 10/26/2020	Data not available	Completed: • Replaced 6.0 miles of existing overhead wire with new insulated wire • Circuit cutover to Lopez 16kV which has higher PSPS thresholds	
31	ED-05207	DONLON	11/25/2021 1/19/2021 1/19/2021	Data not available	Planned Work: • Replace 1.27 miles of existing overhead wire with new insulated wire Completed: • Replaced 6.61 miles of existing overhead wire with new insulated wire	
32	ED-05376	DUKE	12/23/2020 12/7/2020 12/3/2020 12/2/2020	Data not available	Completed: • New insulated wire on most overhead portions of the circuit within HFRA • Replaced 0.4 miles of remaining bare overhead wire within HFRA with new insulated wire • Installed 2 automated switches	
33	ED-05483	DYNAMO	10/19/2019 10/17/2019	Data not available	Planned Work: • Replace 14.24 miles of existing overhead wire with new insulated wire.	

Entry #	Circuit ID [1]	Name of Circuit	Dates of Outages [2]	Number of Customers Hours of PSPS per Outage [3]	Measures taken, or planned to be taken, to reduce the need for, and impact of, future PSPS of circuit [4]	Estimated Annual Decline in PSPS Events and PSPS Impact on Customers
			9/16/2019			
34	ED-05591	ECHO	12/18/2020	Data not available	Completed: • Replaced 2.2 miles of existing overhead wire with new insulated wire	
			12/8/2020			
			10/26/2020			
35	ED-05930	ENERGY	12/17/2024	1,351	Under engineering review for PSPS grid hardening measures Completed: • Replaced 27.41 miles of existing overhead wire with new insulated wire • Installed 3 automated switches and implement additional segmentation • Added temporary generator to serve approx. 120 customers during a PSPS event with minimal outages	
			12/10/2024	53,572		
			12/9/2024	1,476		
			11/6/2024	51,376		
			11/6/2024	1,915		
			11/4/2024	160		
			10/19/2024	193		
			12/9/2023	1,609		
			11/9/2023	462		
			10/30/2023	8,397		
			10/30/2023	195		
			10/29/2023	3,011		
			10/29/2023	2,839		
			11/25/2021	Data not available		
			11/24/2021			
			11/21/2021			
			10/16/2021			
			10/15/2021			
			10/12/2021			
			1/19/2021			
			1/18/2021			
			1/17/2021			
			1/15/2021			
			1/14/2021			
			12/23/2020			
			12/20/2020			
			12/19/2020			
			12/7/2020			
			12/3/2020			
			12/2/2020			
			11/27/2020			
			11/26/2020			
			10/26/2020			
			10/16/2020			

Entry #	Circuit ID [1]	Name of Circuit	Dates of Outages [2]	Number of Customers Hours of PSPS per Outage [3]	Measures taken, or planned to be taken, to reduce the need for, and impact of, future PSPS of circuit [4]	Estimated Annual Decline in PSPS Events and PSPS Impact on Customers
			11/26/2019 10/30/2019 10/28/2019 10/24/2019 10/10/2019			
36	ED-06065	ESTABAN	12/24/2020 12/23/2020 12/7/2020 12/7/2020 12/3/2020 12/3/2020 10/30/2019 10/24/2019 10/24/2019 10/24/2019 10/10/2019	Data not available	Completed: • Replaced 13.8 miles of existing overhead wire with new insulated wire	
37	ED-06357	FERRARA	12/8/2020 11/27/2020 10/26/2020	Data not available	Planned Work: • Replaced 15.84 miles of existing overhead wire with new insulated wire	
38	ED-06432	FINGAL	12/24/2020 12/8/2020 12/7/2020 12/3/2020	Data not available	Completed: • Replaced approximately 33.79 miles of existing overhead wire with new insulated wire	
39	ED-06452	FIREBIRD	12/9/2023 10/30/2023 10/30/2023	9,037 15,563 5,912	Completed: • Replaced 17.59 miles of existing overhead wire with new insulated wire	
40	ED-06888	GABBERT	11/25/2021 11/25/2021 11/25/2021	Data not available	Completed: • Replaced 2.57 miles of existing overhead wire with new insulated wire	
41	ED-07382	GNATCATCHER	12/23/2020 12/7/2020 12/3/2020 11/27/2020 10/30/2019 10/24/2019 10/10/2019	Data not available	Completed: • New insulated wire has already been installed on nearly all existing overhead portions of the circuit • Replaced an additional 3.53 miles of existing overhead wire with new insulated wire at various locations	

Entry #	Circuit ID [1]	Name of Circuit	Dates of Outages [2]	Number of Customers Hours of PSPS per Outage [3]	Measures taken, or planned to be taken, to reduce the need for, and impact of, future PSPS of circuit [4]	Estimated Annual Decline in PSPS Events and PSPS Impact on Customers
42	ED-07742	GUITAR	12/10/2024	4,604	Completed: • Replaced 32.46 miles of existing overhead wire with new insulated wire	
			12/10/2024	109		
			11/6/2024	8,946		
			11/25/2021	Data not available		
			11/22/2021			
			1/19/2021			
			1/19/2021			
			1/15/2021			
			12/23/2020			
			12/3/2020			
			11/27/2020			
			10/26/2020			
			10/30/2019			
			10/28/2019			
			10/24/2019			
			10/11/2019			
43	ED-08446	HILLFIELD	12/23/2020	Data not available	Completed: • Replaced 6.41 miles of existing overhead wire with new insulated wire • Automated 3 switches • Updated switching protocols • Implemented operational protocol for portions of the circuit	
			12/7/2020			
			10/26/2020			
44	ED-08698	HORNTOAD	12/9/2024	2,165	Under engineering review for undergrounding Completed: • Install 1 automated switch Planned Work: • Install 2 automated switches	
			11/6/2024	2,706		
			10/18/2024	1,200		
45	ED-08795	HUCKLEBERRY	10/30/2019	Data not available	Completed: • Replaced 18.27 miles of existing overhead wire with new insulated wire and implement protocols to transfer load to a less affected circuit	
			10/28/2019			
			10/24/2019			
			10/10/2019			
46	ED-08880	ICE HOUSE	12/8/2020	Data not available	Completed: • Replaced 1.08 miles of existing overhead wire with new insulated wire	
			11/27/2020			
			10/26/2020			
			11/25/2021		Completed: • Replaced 25.8 miles of existing overhead wire with new insulated wire	
			11/24/2021			

Entry #	Circuit ID [1]	Name of Circuit	Dates of Outages [2]	Number of Customers Hours of PSPS per Outage [3]	Measures taken, or planned to be taken, to reduce the need for, and impact of, future PSPS of circuit [4]	Estimated Annual Decline in PSPS Events and PSPS Impact on Customers
47	ED-08904	IMPALA	11/21/2021 1/19/2021 12/8/2020 12/3/2020 11/27/2020 10/26/2020 10/26/2020	Data not available		
48	ED-10203	LAUDA	12/10/2024 11/6/2024 11/6/2024	25 27 28	Completed: • Replaced 1.75 miles of existing overhead wire with new insulated wire	
49	ED-10483	LIMITED	12/17/2024 12/9/2024 11/6/2024 10/18/2024	639 4,159 3,956 9,229	Under engineering review for PSPS grid hardening measures	
50	ED-10485	LIMONITE	12/9/2024 11/7/2024 11/6/2024	75 25 6	Under engineering review for PSPS grid hardening measures	
51	ED-10705	LOPEZ	12/8/2020 12/3/2020 10/26/2020	Data not available	Completed: • Replaced 22.4 miles of existing overhead wire with new insulated wire • Installed 1 automated switch	
52	ED-10729	LOUCKS	12/7/2020 11/26/2020 10/26/2020 9/9/2020 10/30/2019 10/28/2019 10/24/2019 10/10/2019	Data not available	Completed:	
53	ED-10934	MAGUIRE	12/17/2024 12/9/2024 11/6/2024	15,439 27,128 37,577	Under engineering review for PSPS grid hardening measures	
54	ED-11500	MCKEVETT	10/30/2019 10/28/2019 10/24/2019 10/24/2019 10/11/2019	Data not available	Completed: • Implemented operational protocol to raise PSPS windspeed thresholds	
			12/10/2024	22,102	Planned Work:	

Entry #	Circuit ID [1]	Name of Circuit	Dates of Outages [2]	Number of Customers Hours of PSPS per Outage [3]	Measures taken, or planned to be taken, to reduce the need for, and impact of, future PSPS of circuit [4]	Estimated Annual Decline in PSPS Events and PSPS Impact on Customers
55	ED-11695	MERLIN	12/9/2024	10,291	• Replace 14.12 miles of existing overhead wire with new underground cable	
			11/6/2024	39,153		
56	ED-11760	METTLER	12/7/2020	Data not available	Completed: • Replaced 38.0 miles of existing overhead wire with new insulated wire	
			12/7/2020			
			12/3/2020			
			12/2/2020			
			11/16/2020			
			10/30/2019			
			10/28/2019			
			10/24/2019			
			10/10/2019			
57	ED-12167	MORA	11/1/2019	Data not available	Completed: • Replaced 4.72 miles of existing overhead wire with new insulated wire	
			10/30/2019			
			10/28/2019			
			10/24/2019			
			10/10/2019			
58	ED-1354	MORGANSTEIN	12/9/2023	40,481	Under engineering review for PSPS grid hardening measures Completed: • Replace 16.16 miles of existing overhead wire with new insulated wire	
			11/20/2023	12,261		
			10/29/2023	10,370		
			11/25/2021	Data not available		
			11/21/2021			
			1/19/2021			
59	ED-12482	NAPA	12/8/2020	Data not available	Completed: • Replaced 17.40 miles of existing overhead wire with new insulated wire	
			12/8/2020			
			12/3/2020			
			12/3/2020			
60	ED-12485	NAPOLEON	12/23/2020	Data not available	Completed: • Replaced 5.8 miles of existing overhead wire with new insulated wire	
			12/8/2020			
			12/7/2020			
			12/3/2020			
			12/2/2020			
61	ED-12700	NICHOLAS	12/17/2024	1,786	Under engineering review for undergrounding	
			12/9/2024	3,761		
			11/6/2024	10,322		
			10/18/2024	4,741		
			9/9/2024	2,119		
			11/20/2023	4,028		

Entry #	Circuit ID [1]	Name of Circuit	Dates of Outages [2]	Number of Customers Hours of PSPS per Outage [3]	Measures taken, or planned to be taken, to reduce the need for, and impact of, future PSPS of circuit [4]	Estimated Annual Decline in PSPS Events and PSPS Impact on Customers
			11/9/2023	2,487		
			10/30/2023	2,714		
			1029/2023	9,213		
62	ED-12847	NORTHPARK	12/10/2024	14,229	Completed: • Replaced 18.6 miles of existing overhead wire with new insulated wire • Implemented switching protocols to transfer load to a less affected circuit • Automated 2 existing sectionalizing devices	
			12/10/2024	125		
			11/6/2024	28,757		
			12/9/2023	100		
			10/30/2023	4,186		
			10/30/2023	170		
			12/24/2020	Data not available		
			12/23/2020			
			12/18/2020			
			12/3/2020			
			11/27/2020			
63	ED-13791	PATRICIA	12/8/2020	Data not available	Completed: • Replaced 33.91 miles of existing overhead wire with new insulated wire	
			12/8/2020			
			12/7/2020			
64	ED-13918	PENSTOCK	12/12/2024	18	Under engineering review for PSPS grid hardening measures Planned Work: • Install 1 automated switch	
			10/18/2024	30		
			8/17/2024	23		
65	ED-13983	PETIT	11/1/2019	Data not available	Planned Work: • Replace 1.21 miles of existing overhead wire with new insulated wire Completed: • Replaced 4.81 miles of existing overhead wire with new insulated wire	
			10/30/2019			
			10/28/2019			
			10/24/2019			
66	ED-14005	PHEASANT	12/23/2020	Data not available	Completed: • Replaced 9.3 miles of existing overhead wire with new insulated wire • Installed 2 automated switches	
			12/7/2020			
			12/3/2020			
67	ED-14190	PLATEAU	12/17/2024	1,883	Under engineering review for undergrounding	
			12/9/2024	8,073		
			11/6/2024	19,752		
			10/18/2024	3,758		
			9/9/2024	853		
			11/25/2021	Data not available		
			11/25/2021			

Entry #	Circuit ID [1]	Name of Circuit	Dates of Outages [2]	Number of Customers Hours of PSPS per Outage [3]	Measures taken, or planned to be taken, to reduce the need for, and impact of, future PSPS of circuit [4]	Estimated Annual Decline in PSPS Events and PSPS Impact on Customers
			11/25/2021			
			1/15/2021			
68	ED-14494	PURCHASE	10/30/2019	Data not available	Completed: • Replaced 2.26 miles of existing overhead wire with new insulated wire	
			10/30/2019			
			10/28/2019			
69	ED-14603	RACER	12/23/2020	Data not available	Completed: • Replaced 0.6 miles of existing overhead wire with new insulated wire • Implemented operational protocols for portions of the circuit	
			12/7/2020			
			12/3/2020			
70	ED-14645	RAINBOW	11/25/2021	Data not available	Completed: • Replaced 15.82 miles of existing overhead wire with new insulated wire • Installed 1 automated switch	
			1/19/2021			
			1/19/2021			
			12/24/2020			
			12/23/2020			
			12/7/2020			
			12/7/2020			
			12/3/2020			
			11/1/2019			
			10/30/2019			
			10/28/2019			
			10/28/2019			
			10/24/2019			
71	ED-14758	RED BOX	12/18/2024	457	Under engineering review for PSPS grid hardening measures	
			12/9/2024	1,172		
			11/6/2024	1,436		
			10/18/2024	788		
			12/8/2020	Data not available	Completed: • Installed an additional weather station • Adjusted switching plans and weather station assignments in order to leverage better situational awareness and reduce PSPS use	
			12/3/2020			
			10/26/2020			
			9/9/2020			
			10/30/2019			
			10/28/2019			
			10/25/2019			
72	ED-15475	ROWCO	12/9/2024	28,413	Under engineering review for PSPS grid hardening measures	
			11/6/2024	2,629		

Entry #	Circuit ID [1]	Name of Circuit	Dates of Outages [2]	Number of Customers Hours of PSPS per Outage [3]	Measures taken, or planned to be taken, to reduce the need for, and impact of, future PSPS of circuit [4]	Estimated Annual Decline in PSPS Events and PSPS Impact on Customers
			10/18/2024	37,191		
73	ED-15586	RUSTIC	12/3/2020	Data not available	Under engineering review for PSPS grid hardening measures Completed: • Replaced 14.36 miles of existing overhead wire with new insulated wire	
			11/27/2020			
			10/26/2020			
74	ED-15618	SADDLEBACK	12/23/2020	Data not available	Completed: • Replaced 3.25 miles of existing bare overhead wire with new insulated wire • Added new weather station near end of the circuit to improve situational awareness	
			12/7/2020			
			12/3/2020			
75	ED-15737	SAND CANYON	12/9/2024	5,430	Under engineering review for PSPS grid hardening measures Completed: • Replaced 30.3 miles of existing overhead wire with new insulated wire. • Circuit is fully covered with Raised Wind Speed Thresholds • Installed 1 automated switch • Identified and increased segmentation for underground portions of the circuit. Updated switching protocols to transfer new segments to an adjacent circuit, mitigating impacts to ~1,800 customers.	
			11/6/2024	3,798		
			11/6/2024	2,534		
			10/18/2024	220		
			12/9/2023	313		
			10/29/2023	667		
			10/29/2023	413		
			11/24/2021	Data not available		
			11/22/2021			
			10/15/2021			
			9/30/2021			
			1/19/2021			
			1/19/2021			
			1/18/2021			
			1/18/2021			
			1/14/2021			
			1/14/2021			
			12/23/2020			
			12/23/2020			
			12/18/2020			
			12/7/2020			
			12/7/2020			
			12/3/2020			
			11/26/2020			
			11/26/2020			

Entry #	Circuit ID [1]	Name of Circuit	Dates of Outages [2]	Number of Customers Hours of PSPS per Outage [3]	Measures taken, or planned to be taken, to reduce the need for, and impact of, future PSPS of circuit [4]	Estimated Annual Decline in PSPS Events and PSPS Impact on Customers
			11/17/2020 10/26/2020 10/26/2020 9/9/2020 10/30/2019 10/28/2019 10/24/2019 10/10/2019			
76	ED-15945	SAVORY	12/8/2020 12/7/2020 12/3/2020	Data not available	Planned Work: • Replace 4.49 miles of existing overhead wire with new insulated wire	
77	ED-16170	SESPE	10/30/2019 10/30/2019 10/11/2019	Data not available	Completed: • Replaced 0.62 miles of existing overhead wire with new insulated wire	
78	ED-16404	SHOVEL	12/7/2020 12/7/2020 12/3/2020 12/3/2020 11/26/2020 11/26/2020 11/17/2020 10/26/2020 9/9/2020 10/29/2019 10/28/2019 10/26/2019 10/24/2019 10/20/2019 10/10/2019	Data not available	Completed: • Replaced 40.19 miles of existing overhead wire with new insulated wire and implement protocols to transfer load to a less affected circuit	
79	ED-16973	STEEL	12/9/2024 11/6/2024 11/6/2024 11/25/2021 11/21/2021 10/15/2021 1/19/2021 12/23/2020	954 381 750	Completed: • Updated switching protocols to reassign the boundary point between PSPS Segment 1 and Segment 2 • Replaced 6.48 miles of existing overhead wire with new insulated wire	

Entry #	Circuit ID [1]	Name of Circuit	Dates of Outages [2]	Number of Customers Hours of PSPS per Outage [3]	Measures taken, or planned to be taken, to reduce the need for, and impact of, future PSPS of circuit [4]	Estimated Annual Decline in PSPS Events and PSPS Impact on Customers
			12/7/2020	Data not available		
			12/7/2020			
			12/3/2020			
			10/30/2019			
			10/28/2019			
			10/24/2019			
			10/10/2019			
80	ED-14732	STUBBY	12/9/2024	52	Completed: • Replaced 27.82 miles of existing overhead wire with ne	
			12/9/2024	51		
			11/6/2024	125		
81	ED-17383	SUTT	11/24/2021	Data not available	Completed: • 3 frequently impacted segments are 100% covered conductor with Raised Wind Speed Thresholds. • Identified and added segmentation for overhead portions of circuit. Updated switching protocols to increase potential customer mitigations. Mitigations dependent on which weather station(s) reaches de-energization thresholds during an event. Reviewing installation of additional remote isolation device. • Installed new weather station 12/13/2023 for increased situtional awareness. Planned Work: • Install 1 automated switch	
			11/21/2021			
			1/19/2021			
			12/18/2020			
			12/8/2020			
			10/26/2020			
82	ED-17546	TAHQUITZ	12/17/2024	548	Under engineering review for PSPS grid hardening meas Completed: • Added new weather station near in the Mountain Center area to improve situational awareness	
			12/10/2024	4,132		
			12/9/2024	901		
			11/6/2024	4,812		
			10/30/2019	Data not available		
			10/28/2019			
			10/24/2019			
			10/11/2019			
83	ED-17487	TAIWAN	12/3/2020	Data not available	Planned Work: • Replace 3.54 miles of existing overhead wire with new insulated wire	
			10/26/2020			
			10/26/2020			
			1/1/2019			
			1/1/2019			

Entry #	Circuit ID [1]	Name of Circuit	Dates of Outages [2]	Number of Customers Hours of PSPS per Outage [3]	Measures taken, or planned to be taken, to reduce the need for, and impact of, future PSPS of circuit [4]	Estimated Annual Decline in PSPS Events and PSPS Impact on Customers
			1/1/2019		Completed: • Replaced 11.76 miles of existing overhead wire with new insulated wire	
84	ED-17529	TANAGER	12/7/2020 12/3/2020 11/27/2020 10/30/2019 10/24/2019 10/10/2019	Data not available	Completed: • Replaced 28.87 miles of existing overhead wire with new insulated wire • Installed 1 new automated switch	
85	ED-17548	TAPO	12/7/2020 12/3/2020 11/26/2020 10/26/2020	Data not available	Completed: • Replaced 11.7 miles of existing overhead wire with new insulated wire • Implemented operational protocol to raise PSPS windspeed thresholds	
86	ED-17880	TIMBER CANYON	11/25/2021 11/25/2021 1/19/2021	Data not available	Planned Work: • Replace 8.04 miles of existing overhead wire with new insulated wire Completed: • Replaced 25.87 miles of existing overhead wire with new insulated wire	
87	ED-18243	TUBA	11/25/2019 10/30/2019 10/24/2019	Data not available	Completed: • Replaced 3.18 miles of existing overhead wire with new insulated wire Planned Work: • Replace 4.97 miles of existing overhead wire with new insulated wire	
88	ED-18252	TUFA	12/11/2020 11/17/2020 11/6/2020	Data not available	Completed: • Replaced 9.41 miles of existing overhead wire with new insulated wire Planned Work: • Replace 11.88 miles of existing overhead wire with new insulated wire	
89	ED-18370	TWIN LAKES	12/23/2020 12/7/2020 12/3/2020	Data not available	Completed: • Implemented operational protocol to raise PSPS windspeed thresholds • Implemented switching protocols to isolate overhead portions and transfer customers to adjacent circuits	

Entry #	Circuit ID [1]	Name of Circuit	Dates of Outages [2]	Number of Customers Hours of PSPS per Outage [3]	Measures taken, or planned to be taken, to reduce the need for, and impact of, future PSPS of circuit [4]	Estimated Annual Decline in PSPS Events and PSPS Impact on Customers
			11/27/2020 10/26/2020			
90	ED-01754	VARGAS	12/23/2020 12/8/2020 12/3/2020 11/27/2020 10/26/2020	Data not available	Completed: • Replaced 0.2 miles of existing overhead wire with new insulated wire • Installed 1 new automated switch • Implemented operational protocol to raise PSPS windspeed thresholds	
91	ED-18650	VERA CRUZ	12/23/2020 12/7/2020 12/3/2020 10/26/2020	Data not available	Completed: • Replaced 8.52 miles of existing overhead wire with new insulated wire • Implemented switching protocols to update boundary between PSPS segment 1 and segment 2 • Installed an additional weather station • Installed 1 new automated switch	
92	ED-19850	ZONE	12/7/2020 12/7/2020 12/7/2020 12/3/2020 12/3/2020 12/3/2020 10/30/2019 10/28/2019 10/24/2019 10/10/2019	Data not available	Completed: • Replaced 23.7 miles of existing overhead wire with new insulated wire • Implemented operational protocols to raise PSPS windspeed thresholds near substation • Circuit is fully covered with Raised Wind Speed Thresholds. Identified and added segmentation for overhead portions of circuit. Updated switching protocols to transfer portions to an adjacent circuit. Transfers dependent on which weather station(s) reaches de-energization thresholds during an event. • Installed an additional weather station	

F2 – Continuation of Section 11

Table 11-5: Collaboration in Local and Regional Wildfire Mitigation Planning

Name of County, City, or Tribal Agency or Civil Society Organization (e.g., nongovernmental organization, fire safe council)	Program, Plan, or Document	Last Version of Collaboration	Level of Collaboration	
Colton	General WMP Plan and PSPS	2023-2025 WMP	SCE + Colton PSPS update meeting	9/24/2024
Jurupa Valley	General WMP Plan and PSPS	2023-2025 WMP	Mayor Requesting PSPS Outreach to a Senior Community	10/25/2024
San Bernardino County	General WMP Plan and PSPS	2023-2025 WMP	Crest Forest & Lake Arrowhead MAC meeting presentation - WMP/PSPS	12/11/2024
Mono County	General WMP Plan and PSPS	2023-2025 WMP	PSPS post-event Government Briefings	12/18/2024
Inyo County	General WMP Plan and PSPS	2023-2025 WMP	PSPS post-event Government Briefings	12/18/2024
Bishop Paiute Tribe	General WMP Plan and PSPS	2023-2025 WMP	PSPS post-event Government Briefings	12/18/2024
Mono Lake Kootzaduka'a Tribe	General WMP Plan and PSPS	2023-2025 WMP	PSPS post-event Government Briefings	12/18/2024
Bridgeport Indian Colony	General WMP Plan and PSPS	2023-2025 WMP	PSPS post-event Government Briefings	12/18/2024
Benton Paiute Tribe	General WMP Plan and PSPS	2023-2025 WMP	PSPS post-event Government Briefings	12/18/2024
Bishop	General WMP Plan and PSPS	2023-2025 WMP	PSPS post-event Government Briefings	12/18/2024

Name of County, City, or Tribal Agency or Civil Society Organization (e.g., nongovernmental organization, fire safe council)	Program, Plan, or Document	Last Version of Collaboration	Level of Collaboration	
Jurupa Valley	General WMP Plan and PSPS	2023-2025 WMP	2024 Post-PSPS Outreach	12/18/2024
Hemet	General WMP Plan and PSPS	2023-2025 WMP	2024 Post-PSPS Briefings Email	12/18/2024
Malibu	General WMP Plan and PSPS	2023-2025 WMP	2024 PSPS Outreach - Presentation to and Meeting with Malibu City Council and Public Safety Commissioner	12/18/2024
Los Angeles County	General WMP Plan and PSPS	2023-2025 WMP	LA County PSPS post-event Government Briefings	12/18/2024
County of Riverside	General WMP Plan and PSPS	2023-2025 WMP	PSPS post-event Government Briefings	12/18/2024
La Canada Flintridge	General WMP Plan and PSPS	2023-2025 WMP	Post PSPS Outreach	12/18/2024
Covina	General WMP Plan and PSPS	2023-2025 WMP	Post PSPS Outreach	12/18/2024
Irwindale	General WMP Plan and PSPS	2023-2025 WMP	Post PSPS Outreach	12/18/2024
Diamond Bar	General WMP Plan and PSPS	2023-2025 WMP	Post PSPS Outreach	12/18/2024
Bloomington	General WMP Plan and PSPS	2023-2025 WMP	Presentation on PSPS information to a Blooming MAC	12/19/2024
Rialto	General WMP Plan and PSPS	2023-2025 WMP	Rialto requested SCE representative to speak with residents about PSPS concerns	12/19/2024

Name of County, City, or Tribal Agency or Civil Society Organization (e.g., nongovernmental organization, fire safe council)	Program, Plan, or Document	Last Version of Collaboration	Level of Collaboration	
Jurupa Valley	General WMP Plan and PSPS	2023-2025 WMP	Post-November PSPS Meeting	12/19/2024
San Bernardino County	General WMP Plan and PSPS	2023-2025 WMP	PSPS Post-Event Government Briefing / Virtual Webinar	12/20/2024
Rolling Hills Estates	General WMP Plan and PSPS	2023-2025 WMP	RHE_PSPS Virtual Workshops for City leadership & emergency managers	12/20/2024
Rolling Hills	General WMP Plan and PSPS	2023-2025 WMP	Community Meeting	12/20/2024
Palos Verdes Estates	General WMP Plan and PSPS	2023-2025 WMP	Community Meeting	12/20/2024
Bloomington	General WMP Plan and PSPS	2023-2025 WMP	Community Meeting	2/13/2025
Villa Park Townhall	General WMP Plan and PSPS	2023-2025 WMP	Community Meeting	03/13/25
Irvine Wildfire Townhall	General WMP Plan and PSPS	2023-2025 WMP	Community Meeting	03/18/25
San Bernardino Mountain Communities Townhall in partnership with Senator Ochoa Bogh & (possibly) County Supervisor Dawn Rowe	General WMP Plan and PSPS	2023-2025 WMP	Community Meeting	03/19/25
GAP/CAP Mtg.	General WMP Plan and PSPS	2023-2025 WMP	PSPS Process Demonstration, Tour, and Meeting	03/19/25

Name of County, City, or Tribal Agency or Civil Society Organization (e.g., nongovernmental organization, fire safe council)	Program, Plan, or Document	Last Version of Collaboration	Level of Collaboration	
Santa Clarita Briefing	General WMP Plan and PSPS	2023-2025 WMP	PSPS Meeting	03/20/25
Ventura County Sup. Parvin's Townhall	General WMP Plan and PSPS	2023-2025 WMP	Community Meeting	03/27/25
Acton Town Council Mtg.	General WMP Plan and PSPS	2023-2025 WMP	PSPS Meeting	TBD end of May
Call with city of Moorpark	General WMP Plan and PSPS	2023-2025 WMP	PSPS Meeting	03/04/25
Beaumont City Council	General WMP Plan and PSPS	2023-2025 WMP	PSPS Meeting	03/04/25
June Lake RPAC	General WMP Plan and PSPS	2023-2025 WMP	PSPS Meeting	03/05/25
Moorpark City Council Presentation	General WMP Plan and PSPS	2023-2025 WMP	PSPS Meeting	03/05/25
Irwindale Emergency Preparedness and Resource Fair	General WMP Plan and PSPS	2023-2025 WMP	PSPS Outreach and Engagement	03/08/25
Four Seasons Beaumont	General WMP Plan and PSPS	2023-2025 WMP	PSPS Meeting	03/12/25
Mono Basin RPAC	General WMP Plan and PSPS	2023-2025 WMP	PSPS Meeting	03/12/25
Bridgeport RPAC	General WMP Plan and PSPS	2023-2025 WMP	PSPS Meeting	03/13/25
Moorpark Chamber Topic on Tap	General WMP Plan and PSPS	2023-2025 WMP	PSPS Meeting	03/13/25

Name of County, City, or Tribal Agency or Civil Society Organization (e.g., nongovernmental organization, fire safe council)	Program, Plan, or Document	Last Version of Collaboration	Level of Collaboration	
Calimesa City Council Mtg	General WMP Plan and PSPS	2023-2025 WMP	PSPS Meeting	03/17/25
SCE GAP Mtg.	General WMP Plan and PSPS	2023-2025 WMP	PSPS Meeting	03/19/25
Long Valley RPAC	General WMP Plan and PSPS	2023-2025 WMP	PSPS Meeting	03/20/25
Mono County Board of Supervisors Meeting	General WMP Plan and PSPS	2023-2025 WMP	PSPS Meeting	04/01/25
Santa Paula Senior Advisory Committee Meeting	General WMP Plan and PSPS	2023-2025 WMP	PSPS Meeting	04/03/25
Simi Valley Chamber	General WMP Plan and PSPS	2023-2025 WMP	PSPS Meeting	04/09/25
Hemet City Manager & Council Briefing	General WMP Plan and PSPS	2023-2025 WMP	PSPS Meeting	TBD
Perris Chamber of Commerce Briefing	General WMP Plan and PSPS	2023-2025 WMP	PSPS Meeting	TBD
Temecula City Mgr, Asst. City Mgr, Fire Chief, Public Works Dir, PIO and Emergency Mgr. Mtg	General WMP Plan and PSPS	2023-2025 WMP	PSPS Meeting	TBD
Grand Terrace Town Hall	General WMP Plan and PSPS	2023-2025 WMP	Community Meeting	TBD
Santa Clarita Valley Economic Development Corporation	General WMP Plan and PSPS	2023-2025 WMP	PSPS Meeting	TBD

Name of County, City, or Tribal Agency or Civil Society Organization (e.g., nongovernmental organization, fire safe council)	Program, Plan, or Document	Last Version of Collaboration	Level of Collaboration	
Forest Falls Community Mtg	General WMP Plan and PSPS	2023-2025 WMP	PSPS Meeting	TBD
Running Springs Chamber of Commerce Community Mtg	General WMP Plan and PSPS	2023-2025 WMP	PSPS Meeting	TBD
Eaton/Palisades Fire Repopulation and Recovering Mtg	General WMP Plan and PSPS	2023-2025 WMP	PSPS Meeting	Ongoing Weekly Mtg.
City of Murrieta Staff	General WMP Plan and PSPS	2023-2025 WMP	PSPS Meeting	TBD
City of Orange Townhall Meeting	General WMP Plan and PSPS	2023-2025 WMP	Community Meeting	Week of March 24th
San Bernardino County Board of Supervisors Meeting w/ Steve Powell	General WMP Plan and PSPS	2023-2025 WMP	PSPS Meeting	TBD
Simi Valley Staff Briefing	General WMP Plan and PSPS	2023-2025 WMP	PSPS Meeting	TBD
Simi Valley City Council	General WMP Plan and PSPS	2023-2025 WMP	PSPS Meeting	TBD
East LA Resource Fair	General WMP Plan and PSPS	2023-2025 WMP	PSPS Meeting	01/11/25
Eaton Fire Press Briefing	General WMP Plan and PSPS	2023-2025 WMP	PSPS Meeting	01/11/25
Eaton Canyon Fire Press Briefing	General WMP Plan and PSPS	2023-2025 WMP	PSPS Meeting	01/11/25
Eaton Canyon Fire Community Meeting	General WMP Plan and PSPS	2023-2025 WMP	PSPS Meeting	01/12/25

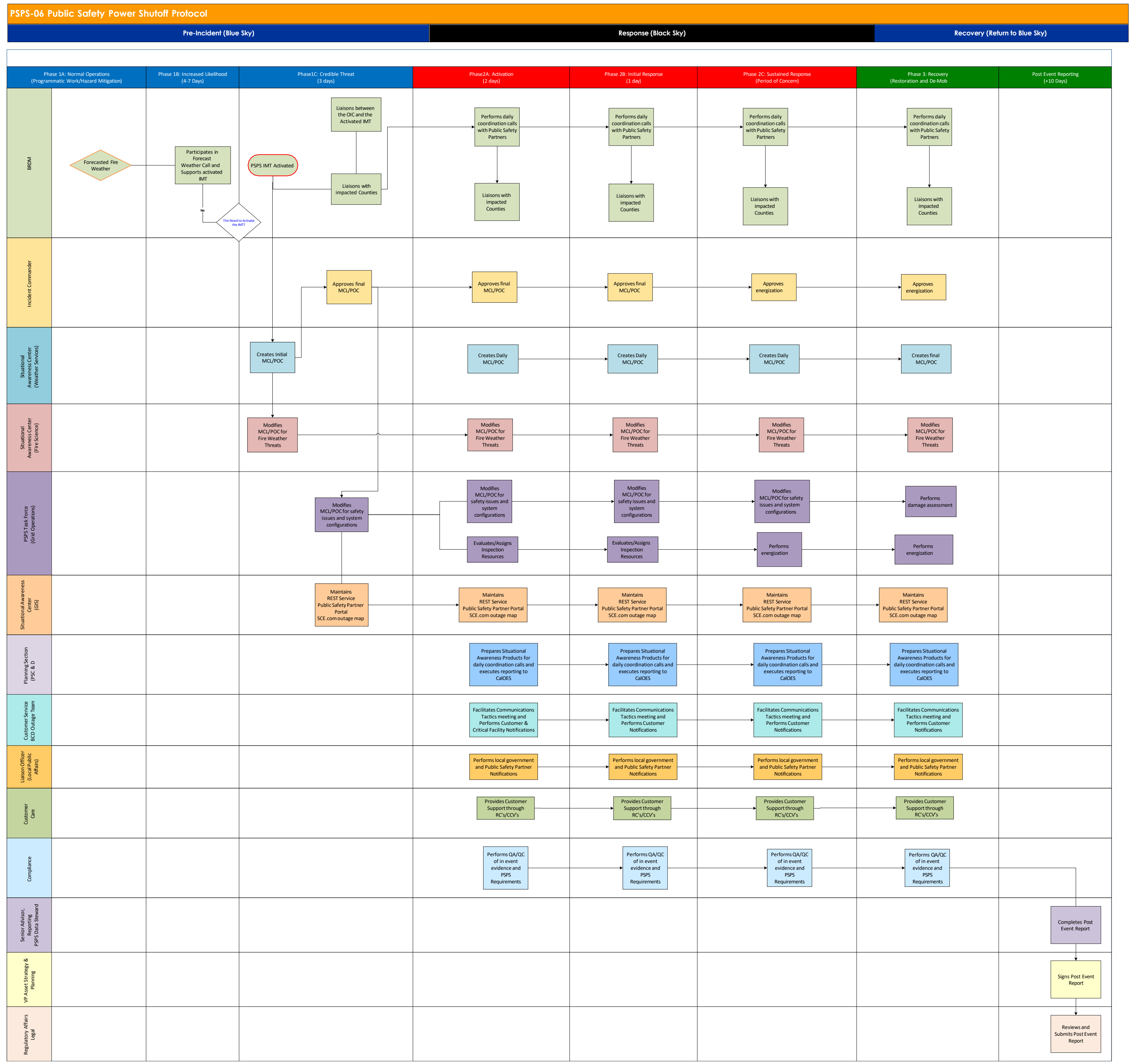
Name of County, City, or Tribal Agency or Civil Society Organization (e.g., nongovernmental organization, fire safe council)	Program, Plan, or Document	Last Version of Collaboration	Level of Collaboration	
Jurupa Valley Town Hall Meeting/District 1	General WMP Plan and PSPS	2023-2025 WMP	PSPS Meeting	01/14/25
Mono City Fire Dept. Community Meeting	General WMP Plan and PSPS	2023-2025 WMP	PSPS Meeting	01/18/25
Eaton Canyon Fire Community Meeting	General WMP Plan and PSPS	2023-2025 WMP	PSPS Meeting	01/19/25
Eaton Canyon Fire Community Mtg	General WMP Plan and PSPS	2023-2025 WMP	PSPS Meeting	01/20/25
Goleta City Council Mtg	General WMP Plan and PSPS	2023-2025 WMP	PSPS Meeting	01/21/25
Tulare Co Supervisor Valero Three Rivers Community Mtg	General WMP Plan and PSPS	2023-2025 WMP	PSPS Meeting	01/22/25
Agoura Hills City Council Mtg	General WMP Plan and PSPS	2023-2025 WMP	PSPS Meeting	01/22/25
Malibu Town Hall on the Palisades Fire	General WMP Plan and PSPS	2023-2025 WMP	PSPS Meeting	01/25/25
San Bernardino County Supervisor Baca Mtg	General WMP Plan and PSPS	2023-2025 WMP	PSPS Meeting	01/27/25
San Bernardino County Supervisors Hagman and Chairwoman Rowe Mtg	General WMP Plan and PSPS	2023-2025 WMP	PSPS Meeting	01/27/25
Mono & Inyo Counties Community Mtg	General WMP Plan and PSPS	2023-2025 WMP	PSPS Meeting	01/28/25

Name of County, City, or Tribal Agency or Civil Society Organization (e.g., nongovernmental organization, fire safe council)	Program, Plan, or Document	Last Version of Collaboration	Level of Collaboration	
Fillmore City Council Mtg.	General WMP Plan and PSPS	2023-2025 WMP	PSPS Meeting	01/28/25
Laguna Beach City Staff	General WMP Plan and PSPS	2023-2025 WMP	PSPS Meeting	01/29/25
Rosena Ranch HOA Update	General WMP Plan and PSPS	2023-2025 WMP	PSPS Meeting	01/29/25
City of Yucaipa Podcast	General WMP Plan and PSPS	2023-2025 WMP	PSPS Meeting	02/04/25
Bloomington MAC	General WMP Plan and PSPS	2023-2025 WMP	PSPS Meeting	02/05/25
San Bernardino County Fire Dept/ Office of Emergency Services Mtg	General WMP Plan and PSPS	2023-2025 WMP	PSPS Meeting	02/05/25
San Gabriel Valley Council of Governments	General WMP Plan and PSPS	2023-2025 WMP	PSPS Meeting	02/10/25
VICA Roundtable Discussion on Post-Wildfire Rebuilding Efforts	General WMP Plan and PSPS	2023-2025 WMP	PSPS Meeting	02/11/25
Loma Linda City Council Mtg.	General WMP Plan and PSPS	2023-2025 WMP	PSPS Meeting	02/11/25
Four Seasons Hemet HOA Mtg	General WMP Plan and PSPS	2023-2025 WMP	PSPS Meeting	02/13/25
Diamond Bar City Council Mtg.	General WMP Plan and PSPS	2023-2025 WMP	PSPS Meeting	02/18/25
Piru Neighborhood Council Emergency	General WMP Plan and PSPS	2023-2025 WMP	PSPS Meeting	02/18/25

Name of County, City, or Tribal Agency or Civil Society Organization (e.g., nongovernmental organization, fire safe council)	Program, Plan, or Document	Last Version of Collaboration	Level of Collaboration	
Fire Preparedness Meeting				
City of Rancho Palos Verdes Wildfire Preparedness TownHall	General WMP Plan and PSPS	2023-2025 WMP	Community Meeting	02/20/25
Chino Hills Fire Preparedness PSPS Update Meeting	General WMP Plan and PSPS	2023-2025 WMP	PSPS Meeting	02/24/25
Jurupa Valley City Council Special Session	General WMP Plan and PSPS	2023-2025 WMP	PSPS Meeting	02/27/25
Altadena Town Council (Leaders) Briefing	General WMP Plan and PSPS	2023-2025 WMP	PSPS Meeting	02/27/25
Claremont City Council Special Meeting: Wildfire Preparedness Community Workshop	General WMP Plan and PSPS	2023-2025 WMP	PSPS Meeting and Workshop	03/01/25
Orange County Supervisor Don Wagner	General WMP Plan and PSPS	2023-2025 WMP	PSPS Meeting	03/03/25
PSPS Working Group	General WMP Plan and PSPS	2023-2025 WMP	PSPS Working Group meets quarterly by CalOES region	3/13/2025
PSPS Advisory Board	General WMP Plan and PSPS	2023-2025 WMP	PSPS Advisory Board meets quarterly service territory wide	3/18/2025
Government Advisory Panel (GAP)/Consumer	General WMP Plan and PSPS	2023-2025 WMP	SCE wildfire/windstorm and response recovery; SCE leadership meets	3/19/2025

Name of County, City, or Tribal Agency or Civil Society Organization (e.g., nongovernmental organization, fire safe council)	Program, Plan, or Document	Last Version of Collaboration	Level of Collaboration	
Advisory Panel (CAP)			several times a year with GAP/CAP members including local/tribal government elected officials	
Mono County & Town of Mammoth Lakes	General WMP Plan and PSPS	2023-2025 WMP	Local Hazard Mitigation Plan (LHMP)& WMP & PSPS Collaboration	3/13/2025
Eastern Sierra Wildfire Alliance	General WMP Plan and PSPS	2023-2025 WMP	WMP & PSPS Collaboration	11/15/2024

Figure SCE 11-01c: SCE's PSPS Operational Flow Diagram



F3 – ACI SCE-25U-03 Grid Hardening

Joint IOU Grid Hardening Working Group Report: Update for 2026-2028 Wildfire Mitigation Plan

[3/19/2025]
Submitted on behalf of the following:

Southern California Edison Company (SCE)
San Diego Gas & Electric Company (SDG&E)
Pacific Gas and Electric Company (PG&E)

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Introduction

In the final decisions for 2025 Wildfire Mitigation Plan (WMP) Updates for the Joint Investor-Owned Utilities (IOUs), the Office of Energy Infrastructure Safety (Energy Safety) issued an Area for Continuing Improvement (ACI) requiring the continuation of joint grid hardening studies from the 2023-2025 Base WMP. The ACI was identified as follows in the decisions for each utility:

- SCE-25U-03
- SDGE-25U-04
- PG&E-25U-03

This report serves as the Joint Utility response to the ACI. The language from the ACI is presented in italics, with the Joint Utility response presented in non-italics.
In many sections of this report, the Joint Utilities have presented a unified response to provide Energy Safety and other stakeholders with a combined narrative. The Joint Utilities note that each utility's individual practices may vary, both in the present day and in the future. As such, statements in this report about how the Joint Utilities approach specific issues or situations should be taken with the understanding that variations at each utility may exist.

ACI Description

Continuation of Grid Hardening Joint Studies
As directed in the 2023-2025 WMP Decisions, the IOUs have made progress on the areas for continued improvement related to the continued joint IOU grid hardening working group efforts. Energy Safety expects the IOUs to continue these efforts and meet the requirements of this ongoing area for continued improvement.

ACI Required Progress

In its 2026-2028 Base WMP, [each utility] must continue to collaborate with the other IOUs to evaluate various aspects of grid hardening and provide an updated Joint IOU Grid Hardening Working Group Report. This report must include continued analysis for the following:
(continued on following page)

Topic #1: Covered Conductor

The IOUs' continued joint evaluation of the effectiveness of CC for reducing ignition risk, PSPS risk, and outage risk associated with protective equipment and device settings. This evaluation must include analysis of risk reduction observed in-field as well as research on CC degradation over time and its associated lifetime risk mitigation effectiveness.

The Joint Utilities conduct a California Utility Wildfire Risk Reduction meeting on a monthly basis. Covered conductor (CC) is discussed as part of this meeting. This section details the evaluation of CC for reducing risks associated with protective equipment and device settings.

Ignition risk

SCE

As outlined in earlier WMPs, each utility's CC program varies due to factors such as location, terrain, and existing overhead facilities. Additionally, each utility has unique ignition frequencies, risk drivers, and deployment volumes. These characteristics, among others, lead to variations in data, calculations, and methods for estimating effectiveness. At SCE, CC is the primary mitigation implemented for Overhead Hardening, except in cases in which the level of risk is sufficiently high to merit undergrounding the lines (please see SCE's Integrated Wildfire Mitigation Strategy as described in its WMP Section 5). SCE's mitigation effectiveness for its Wildfire Covered Conductor Program (WCCP) program is estimated to be 60 percent (see discussion in SCE's 2026-2028 WMP, Chapter 5). This value is based on testing, ignition data, experience, benchmarking, and Subject Matter Expert (SME) judgement. SCE completed extensive third-party CC testing in 2022, as provided in the 2023-2025 Joint IOU Covered Conductor Working Group report.

PG&E

PG&E's overhead hardening program consists of primary and secondary CC replacement along with pole replacements, replacement of non-exempt equipment, replacement of overhead distribution line transformers, framing and animal protection upgrades, and vegetation clearing. Although the focus of this request is CC, PG&E's efforts to estimate effectiveness include all elements of our Overhead Hardening program, which is more complete than CC alone.

As detailed in Section 8.2.1 of PG&E's 2026-2028 WMP, based on historical analysis of ignitions, PG&E estimates the effectiveness of CC at reducing ignition risk in the PG&E service territory to be 67 percent. When combined with Enhanced Power Line Safety Settings (EPSS) and Downed Conductor Detection (DCD), PG&E estimates the ignition risk reduction effectiveness increases to 79 percent.

SDG&E

In 2025, SDG&E calculated CC effectiveness using ignitions and evidence of heat data from 2019 to 2024. Outputs of CC testing and benchmarking with the Joint Utilities were also utilized to update the effectiveness of CC at preventing ignitions from risk drivers. The effectiveness of CC varies based on the wildfire risk driver. When combined with other mitigations such as falling conductor protection and early fault detection, overall ignition reduction for all risk drivers is 56.7 percent. By applying these findings to actual ignition counts, SDG&E estimates that the use of covered conductors is 44 percent effective at reducing wildfire risk.

PSPS risk

Due to CC's ability to reduce the risk of contact from foreign objects, wind speed de-energization thresholds on fully covered circuit segments can be raised from National Service Wind Advisory levels (31 mph sustained wind speed and 46 mph gust wind speed) to National Weather Service High Wind Warning levels (40 mph sustained wind speed and 58 mph gust wind speed). However, wind speed thresholds for de-energization of covered conductor segments vary due to each utility's risk tolerance and the unique circumstances impacting each PSPS event.

As part of their processes, the Joint Utilities analyze circuits impacted by PSPS. If the analysis shows that future de-energizations can be mitigated by CC, then CC will be considered. Additionally, analysis is now proactively performed on circuits that are at risk for PSPS but have not yet been impacted. CC will be considered for deployment on these circuits as necessary pending the results of the analysis.

Outage risk associated with protective equipment and device settings

The Joint Utilities deploy protective equipment and device settings in conjunction with CC, such as EPSS for PG&E, fast curve for SCE, or Sensitive Relay Profiles (SRP) for SDG&E. CC may not have a direct impact on the outage risk associated with protective equipment and device settings. For example, even though CC may decrease the likelihood of transient level faults experienced by the utility, it could also increase the likelihood of a downed wire that would not be de-energized by standard device setting practices. Therefore, the utilities are continuing to develop and implement new devices and methodologies for clearing what would be experienced as open-wire scenarios.

PG&E

See Sections 5.1.1 and 8.7.1.1 of PG&E's 2026-2028 WMP for discussion of outage risk and protective equipment.

SDG&E

See Section 4.1.2 and 4.1.4 for SDG&E's utilization of protective equipment and section 5.1 for analysis on mitigations deployed in combination with CC.

SCE

See Section 8.2.8, 8.7.1, 8.7.2, and 10.3.1 of SCE's 2026-2028 WMP for SCE's discussion of sectionalizing and protection devices and settings.

1.1.4 *Risk reduction observed in-field*

The Joint Utilities have continued to refine their data and methods to measure the effectiveness of CC in the field. Factors such as outage data, scored by SMEs and based on qualitative criteria (e.g. Equipment Type, Basic Cause, Outage Driver, etc.), are used to measure the effectiveness of CC in the field. Promising studies are underway with major California universities to monitor and produce meaningful observed effectiveness results, including the use of Bayesian inferences; however, data availability is a constraint given the relative novelty of CC installation programs. Ideally, SME-based assessment of effectiveness will not be relied on long term, but limited real-world observations of CC will support the assumptions used. For example, PG&E has experienced two ignitions involving CC. Both incidents experienced large vegetation failures that broke through the CC, resulting in wire down incidents that ignited ground fuels. Although both incidents occurred in locations where CC was installed, the vegetation failures were so large that the hardened circuit was not able to withstand the contact. These events reinforce PG&E's methodology of "medium" effectiveness for tree fall-in associated with wire on object and wire on ground ignitions.

PG&E

PG&E's overhead hardening program consists of primary and secondary CC replacement along with pole replacements, replacement of non-exempt equipment, replacement of overhead distribution line transformers, framing and animal protection upgrades, and vegetation clearing. Although the focus of this request is CC, PG&E's efforts to estimate effectiveness include all elements of our Overhead Hardening program, which is more complete than CC alone.

Determining whether a specific event could result in an ignition depends upon a wide variety of factors, including the nature of the event itself and prevailing environmental conditions (e.g., weather, ground moisture level, time of year). As PG&E does not have complete information to make this determination for each event, estimating overhead hardening effectiveness relies upon several assumptions. Most distribution outages (momentary and sustained) typically involve a fault condition. Thus, for purposes of estimating overhead hardening effectiveness, it is assumed that all distribution outages could potentially result in an ignition, regardless of other prevailing conditions. This approach aligns with what has been previously stated in PG&E's 2023 WMP and 2024 RAMP filing.

In 2023, PG&E re-evaluated the SME effectiveness designations and adjusted the estimated ignition effectiveness of CC in a few key areas based on an assessment of the Joint IOU grid hardening testing results. While this is expected to be an ongoing process, effectiveness values have been refreshed 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, as discussed above, there are trees in our service territory large enough to damage CC and as such, CC does not have as substantial an increase in effectiveness.

- Contact from Object Vehicle changed from “none” (not effective) to “medium” (some effectiveness). PG&E agrees with other IOUs that CC has some limited benefit. Given that PG&E is installing larger poles to support CCs, the larger poles have the potential to sustain more impact from vehicle than existing infrastructure.

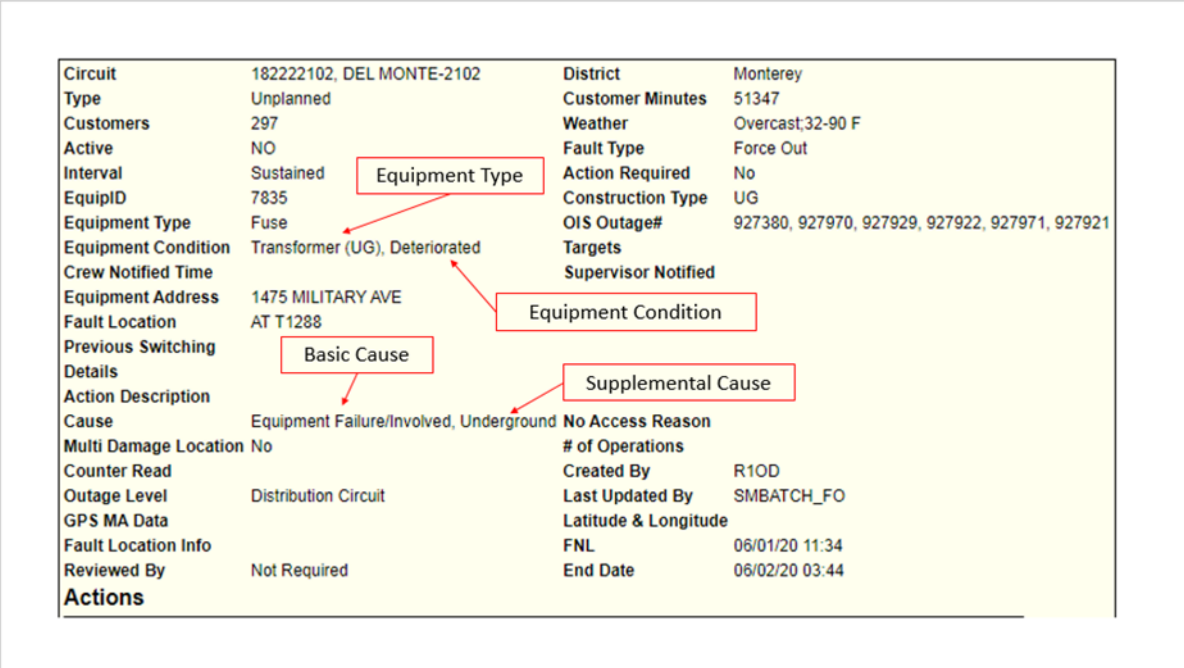
- Animal caused outages associated with conductor contact changed from “none” (not effective) to “All” (very high effectiveness). Testing on the covering material of CCs showed a high resiliency to damage. Also, PG&E found that the insulating properties of the covering did not diminish significantly when damaged. Therefore, PG&E has increased CC effectiveness for mitigating damage caused by animals such as squirrels and birds.

In the 2024 update, the analysis was updated to be more granular, and additional mitigation alternatives, including undergrounding, were added as a consideration. Given the many combinations of outage types seen on PG&E’s system, SMEs highlighted the need to differentiate effectiveness in a more granular level for some of the outage conditions. Therefore, qualitative categorization levels used in the analysis were increased from five (All, High, Medium, Low, None) to seven (All, Very High, High, Medium High, Medium, Low, None).

PG&E’s approach to calculating estimated effectiveness of CC is detailed below:

1. SMEs identified approximately 100,000 distinct outages between 2015 and 2024 by using all known combinations of basic cause, supplemental cause, equipment type, and equipment condition from the distribution outage database, shown in Figure 1. Whenever an outage is reported, an operator enters the required information about the outage. Through SME evaluation, it was decided that a combination of the four aforementioned combination fields provide an appropriate distinction of different outage types.

Figure 1: PG&E Distribution Outage Database Record



Circuit	182222102, DEL MONTE-2102	**District**	Monterey
Type	Unplanned	**Customer Minutes**	51347
Customers	297	**Weather**	Overcast;32-90 F
Active	NO	**Fault Type**	Force Out
Interval	Sustained	**Action Required**	No
EquipID	7835	**Construction Type**	UG
Equipment Type	Fuse	**OIS Outage#**	927380, 927970, 927929, 927922, 927971, 927921
Equipment Condition	Transformer (UG), Deteriorated	**Targets**	
Crew Notified Time		**Supervisor Notified**	
Equipment Address	1475 MILITARY AVE		
Fault Location	AT T1288		
Previous Switching Details			
Action Description			
Cause	Equipment Failure/Involved, Underground	**No Access Reason**	
Multi Damage Location	No	**# of Operations**	
Counter Read		**Created By**	R1OD
Outage Level	Distribution Circuit	**Last Updated By**	SMBATCH_FO
GPS MA Data		**Latitude & Longitude**	
Fault Location Info		**FNL**	06/01/20 11:34
Reviewed By	Not Required	**End Date**	06/02/20 03:44
Actions			

2. SMEs identified whether the presence of CC would eliminate or reduce the potential of an ignition from each outage combination based on the qualitative categorizations below:
    - **All** = Eliminates the likelihood of ignition from a certain type of outage
    - **Very High** = Addresses most outage concerns, but OH construction still has the potential for outage events resulting in an ignition
    - **High** = Significant outage reduction, however still chance that contact failure would result in an ignition
    - **Medium High**= Better than average likelihood of reducing ignitions from a certain type of outage
    - **Medium =** Moderately reduces the likelihood of a certain type of outage occurring resulting in an ignition
    - **Low** = Minimally reduces the likelihood of a certain type of outage occurring resulting in an ignition
    - **None** = Will not affect the likelihood of ignition from a certain type of outage
3. Each qualitative category was assigned a quantitative value, which measured the likelihood of outage reduction:
    - All = 100 percent
    - Very High = 90 percent
    - High = 70 percent

- Medium High = 60 percent
- Medium = 40 percent
- Low = 20 percent
- None = 0 percent

4. The above criteria were applied to historical outages, which resulted in the likelihood of outage reduction for each outage.
5. Outages were classified by drivers in alignment with PG&E's current Wildfire Distribution Risk Model (WDRM v4). The outage drivers identified are:
    - Animal (Bird)
    - Animal (other)
    - Animal (Squirrel)
    - Equipment (Capacitor)
    - Equipment (DPD)
    - Equipment (Fuse)
    - Equipment (other)
    - Equipment (Support Structure)
    - Equipment (Switch)
    - Equipment (Transformer)
    - Equipment (Voltage Control)
    - Primary Conductor - Line Slap
    - Primary Conductor - Other
    - Primary Conductor - Wire Down
    - Secondary Conductor
    - Third Party (Balloon)
    - Third Party (other)
    - Third Party (Vehicle)
    - Vegetation (Branch)
    - Vegetation (other)
    - Vegetation (Trunk)

    One additional "Company Initiated" driver was created, but outages associated with this driver are excluded from results of the analysis. This category includes outages such as PSPS events.

6. A Pivot table was then created to aggregate outages in the HFTD. The aggregation was done at the outage driver level and the results are shown in Table 1.

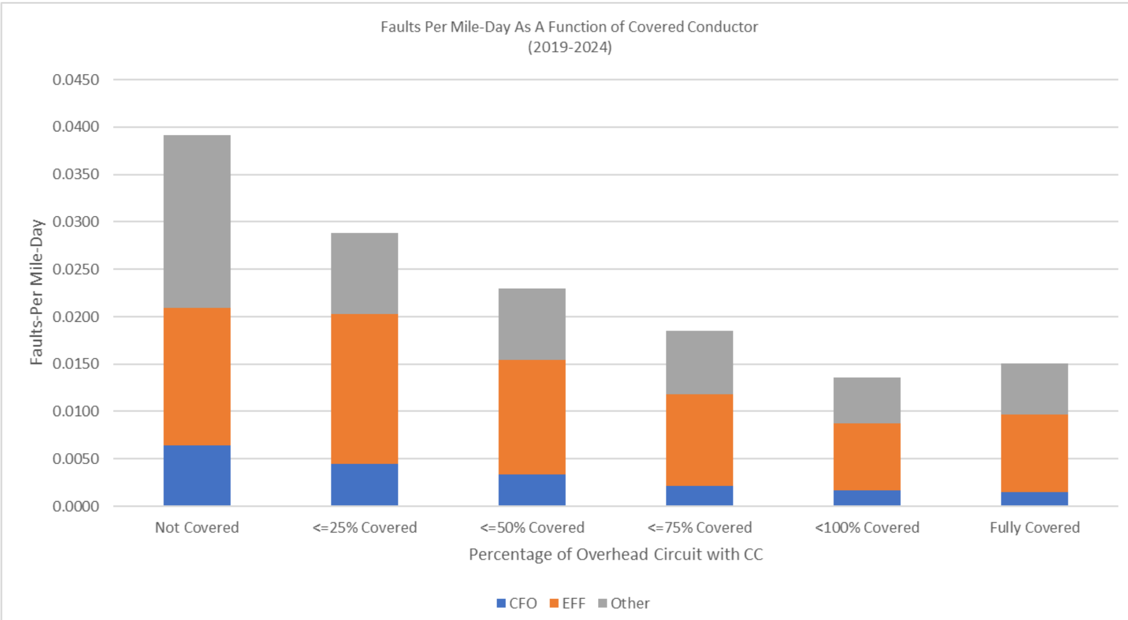
Table 1: PG&E Covered Conductor Mitigation Effectiveness Estimate

WDRM V4 Driver	Overhead Hardening	UG Primary and OH Secondary	UG Primary and UG Secondary
Vegetation (Branch)	76%	98%	100%
Vegetation (Trunk)	58%	98%	100%
Vegetation (other)	83%	97%	100%
Animal (Bird)	79%	100%	100%
Animal (Squirrel)	74%	100%	100%
Animal (other)	78%	99%	100%
Third Party (Balloon)	88%	100%	100%
Third Party (Vehicle)	64%	99%	100%
Third Party (other)	52%	71%	73%
Primary Conductor - Line Slap	85%	99%	99%
Primary Conductor - Wire Down	47%	100%	100%
Primary Conductor - Other	74%	100%	100%
Secondary Conductor	50%	50%	99%
Equipment (Support Structure)	73%	100%	100%
Equipment (Transformer)	70%	100%	100%
Equipment (Voltage Control)	32%	96%	98%
Equipment (other)	76%	94%	94%
Equipment (Capacitor)	41%	91%	91%
Equipment (DPD)	40%	97%	98%
Equipment (Fuse)	73%	100%	100%
Equipment (Switch)	81%	99%	99%
Grand Total	67%	98%	99%

SCE

SCE tracks fault rates on overhead distribution circuits with 100 percent CC installed, circuits that are partially covered, and circuits with no CC installed (bare wire). The data can be broken down by fault sub-drivers such as Contact from Object, Equipment/Facility Failure, and Other. The data is based on all circuits that traverse the HFTD and includes a breakdown of how many miles there are in the fully covered, partially covered, and not covered categories. Because it is difficult to determine if faults on partially covered circuits occurred on the covered or bare portion, SCE further delineated this data into the following partially covered groups: less than 25, 25 to 49, 50 to 74, 75 percent, and less than 100 percent. Furthermore, SCE is now using a faults-per-mile-per-day method that factors in how long the circuit was fully or partially covered. Faults-per-mile-per-day data from 2019 to 2024 are shown in Figure 2.

Figure 2: Faults Per Mile per Day as a Function of CC



There are currently no changes to the near-term approach for evaluating effectiveness. SCE will continue to track and analyze ignition events and may leverage this data to refine current assumptions for estimated effectiveness.

Research on CC degradation over time and its associated lifetime risk mitigation effectiveness

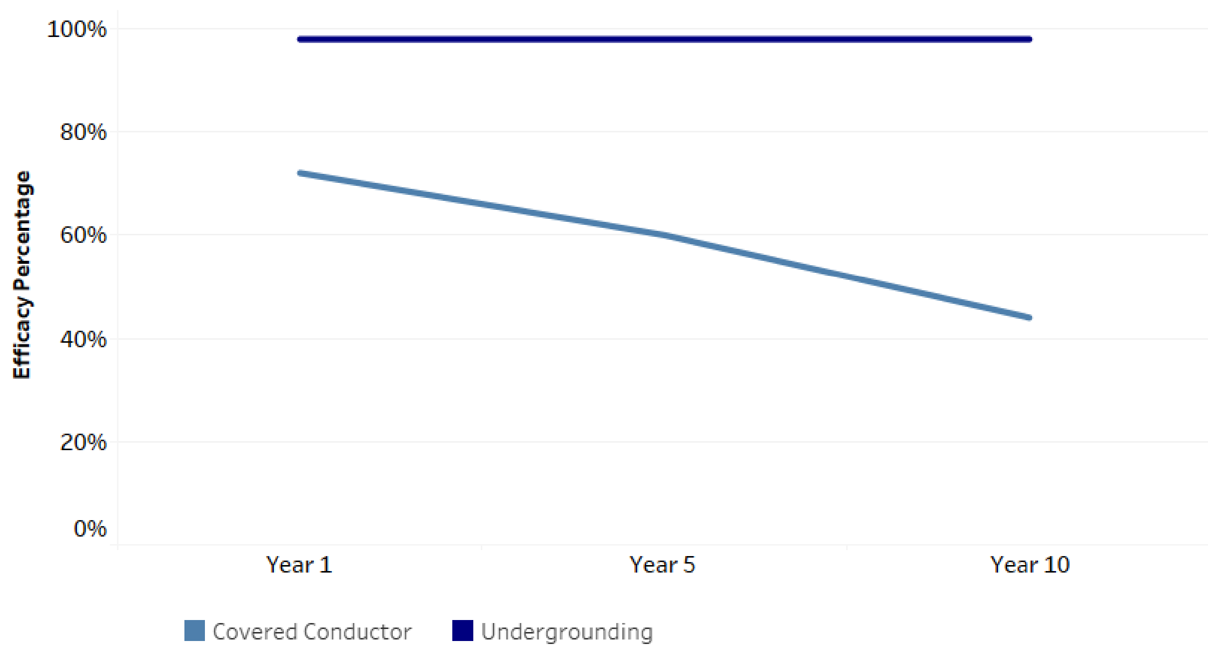
Over the last few years, the Joint Utilities have conducted extensive testing on CC. These tests included third-party testing in 2022, which included contact-from-obvious testing, wire down, flammability, and water ingress. In addition, the Joint Utilities require manufacturers to perform ultraviolet resistance and track resistance testing (to prevent covering degradation caused by electrical charges on the outer portion of the CC covering). Based on tests, benchmarking information, and manufacturer feedback, SCE estimates the useful life of CC to be 45 years. SCE does not expect a reduction of mitigation effectiveness for CC within these 45 years.

PG&E utilizes 48 years as the estimated service life for CC, which aligns with industry information citing an expected service life in the range of 30 to 50 years. PG&E has a large service territory with varying environmental conditions that impact equipment aging and degradation in different ways. For example, testing results indicate that equipment degradation can be increased in damp locations, such as the coast where fog is more common. Therefore, PG&E does not have an estimated service life for CC. However, 30-50 years is the expected service life according to industry information.

SDG&E

The effectiveness of CC against various equipment failure risk drivers was reduced in 2025 for several reasons. Originally, the estimated effectiveness was derived using a year-over-year approach. Effectiveness was defined as the immediate protection gained from performing the CC installation, which replaces aging or damaged equipment with new equipment. However, because these effectiveness numbers are being utilized for long-term investment planning, it is more appropriate to utilize a long-term effectiveness number for risk drivers. While CC installation replaces aging equipment, covered conductors will also age and degrade, reducing the effectiveness of the original installation over time. To address this issue, previous studies on the effectiveness of traditional (bare conductor) hardening were used to estimate the effectiveness of CC on equipment failure risk drivers over time. As shown in Figure 3, traditional hardening had an estimated effectiveness of approximately 65 percent in the first year that decreased over the course of 10 years to 39 percent. Because of the similarities in equipment being replaced during covered conductor and traditional hardening initiatives, the 10-year recorded effectiveness of 39 percent for traditional hardening effectiveness against equipment failure risk events was also used to calculate CC effectiveness for the same equipment failure risk drivers, resulting in a decrease in covered conductor efficacy from 72 percent in the first year to 44 percent after 10 years.

Figure 3: Hardening Efficacy over Time



Combined Mitigation Effectiveness Updated CC effectiveness values were utilized to study the combined effectiveness of CC with the Advanced Protection initiatives of FCP and EFD. Much like CC installations, FCP installations are new and therefore no recorded data is available for calculating effectiveness. Therefore, subject matter expertise from the System

Protection and Controls Engineering (SPACE) team was utilized to estimate their effectiveness. EFD was calculated using data as described in ACI-SDGE-25–05 (see SDG&E's 2026-2028 Wildfire Mitigation Plan, Appendix D). When combining mitigations, the following formula was used (in collaboration with the Joint Utilities):

$$Combined\ Effectiveness$$
$$= 1 - [(1 - CC\ Efficacy) \times (1 - FCP\ Efficacy) \times (1 - EFD\ Efficacy)]$$

$$1 - [(1 - 44\%)] \times (1 - 8\%) \times (1 - 16\%) = 56.7\%$$

The overall efficacy of CC conductors is estimated to be 44 percent and the overall efficacy of CC combined with FCP and EFD is estimated to be 56.7 percent.

Topic #2: Undergrounding

The IOUs' joint evaluation of the effectiveness of undergrounding for reducing ignition risk, PSPS risk, and outage risk associated with protective equipment and device settings. This evaluation must account for any remaining risk from secondary or service lines and analysis of in-field observations from potential failure points of underground equipment.

The Joint Utilities continued to meet quarterly in 2023 and 2024 to share information and lessons learned regarding undergrounding within California and to participate in efforts to share and learn from utilities implementing underground programs outside California. In August 2023, PG&E and SDG&E participated in an Electric Power Resource Institute (EPRI)-sponsored 2-day in-person session with utilities from across the country to discuss topics such as undergrounding program motivations, operations, challenges, and efficiencies. In April 2024, PG&E published an undergrounding benchmarking report that discussed program approaches and trends for 11 electric utilities, including all three California IOUs. See Section 2.2 for details on this report.

Because every utility considers unique factors for selecting undergrounding, as well as environmental factors contributing to the feasibility and effectiveness of undergrounding, data and lessons learned from one utility are not always applicable to other utilities. However, the California utilities intend to continue meeting regularly to ensure communication and sharing of information and will apply lessons learned whenever applicable and participate in national undergrounding-related information-sharing opportunities.

Joint Evaluation of effectiveness of undergrounding for reducing Ignition risk:

Among the Joint Utilities, the estimated effectiveness of undergrounding at reducing ignition risk in a given location ranges from 94 to 99 percent. While the joint utilities' effectiveness rates are highly aligned and indicate that undergrounding is very effective in reducing ignition risk, the exact figures vary slightly due to differences in assumptions and methodologies used to calculate effectiveness values, differences in territory topography and weather, and differences in data, such as outage type and frequency, for past outages and ignitions.

PG&E estimates the ignition mitigation effectiveness of undergrounding primary powerlines to be approximately 98 percent and approximately 99 percent if both the primary and secondary services are undergrounded. Effectiveness is derived by using outages as a proxy for ignitions as well as subject matter expertise. PG&E provides additional information on calculating mitigation effectiveness in its 2026-2028 WMP, Section 8.2.1.

Joint Evaluation of effectiveness of undergrounding for reducing PSPS risk

PG&E

Beyond PG&E's projects targeted to reduce PSPS, lines that are undergrounded may be exempt from PSPS activity as the underground lines themselves do not pose an ignition risk during the extreme weather conditions that drive PSPS events. However, it is challenging for PG&E to provide a PSPS risk effectiveness value for undergrounding because the PSPS effectiveness of undergrounding in any particular location depends on whether, and how much of the upstream and downstream line sections have been undergrounded. For example, undergrounding may not eliminate PSPS risk for customers directly connected to an underground section of a circuit if the undergrounded section remains connected to an overhead line (either upstream or downstream) in a High Fire Risk Area (HFRA) that is subject to PSPS. While overhead hardening does not automatically exempt a location from a PSPS event, the hardened status of a line, and of any overhead upstream and downstream lines, is considered in the analysis that determines which lines are scoped into a PSPS event. As PG&E completes additional undergrounding and underground sections are connected, more PSPS risk will be mitigated.

SCE

SCE has not quantified the effectiveness of Targeted Undergrounding (TUG) on PSPS risk. However, SCE would no longer have PSPS as the line is now underground, but a customer on a UG circuit could potentially be subject to PSPS if they are downstream of a segment that is de-energized and SCE can't otherwise section them off.

SDG&E

SDG&E subject matter experts from Meteorology, Fire Science, Engineering, and Risk Analytics groups are currently assessing the effectiveness of existing underground infrastructure considering the most recent fire weather conditions experienced in SDG&E's service territory from November 2024 to January 2025. This evaluation aims to determine the frequency and duration of SDG&E's most recent PSPS de-energizations on underground segments and identify any necessary improvements to SDG&E's risk models. In addition, subject matter experts are evaluating the criteria for selecting future undergrounding projects based on the hardening status of upstream and downstream feeder segments. With this new approach, SDG&E aims to maximize PSPS risk reduction while balancing ignition risk reduction in the most cost-effective manner.

Joint Evaluation of effectiveness of undergrounding for reducing outage risk associated with protective equipment and device settings

PG&E analyzed the reliability performance of circuit sections where System Hardening Undergrounding work was performed in 2022 and 2023 to quantify overall improvements to service reliability. The analysis included approximately 750 outages between 2021 and 2024 and showed an approximate 90 percent reduction in faults that resulted in sustained outages.

How the effectiveness evaluation accounts for remaining risk from secondary or service lines

SDG&E

SDG&E's undergrounding program is inclusive of primary, secondary and service lines, thus limiting risk from secondary or service lines remaining overhead.

PG&E

While PG&E's distribution undergrounding program currently includes primary powerlines and secondary lines that run parallel to the primaries, PG&E expects that when the undergrounding program is transitioned to the EUP it will include some secondary and service lines in addition to primary lines in the HFTD. PG&E provides mitigation effectiveness values for Undergrounding All, which includes primary distribution lines, secondary lines, and services in PG&E's 2026-2028 Base WMP, Table PG&E 8.2.1-3, Section 8.2.1.

SCE

SCE's program currently focuses on undergrounding primary conductor and does not underground lateral secondary lines and service conductors. As such, SCE has not developed effectiveness values for secondary/service risk. For SCE's TUG program, secondaries will be included as part of the scope when possible and services are not part of the TUG scope.

How the effectiveness evaluation accounts for in-field observations from potential failure points of underground equipment

PG&E tracks data from ignition events and other failures by underground distribution infrastructure equipment. Data is analyzed and used to make updates to equipment and process standards. If relevant to wildfire mitigation effectiveness, updated standards may be leveraged to refine assumptions for estimated effectiveness of undergrounding in preventing wildfire ignitions. However, this data does not directly impact effectiveness values because failure modes of underground equipment are not typically affected by factors that are associated with wildfire risk. For example, extreme high wind conditions, which can be associated with higher ignition risk, do not trigger failures in underground lines because the lines are underground and thus not impacted by wind.

The IOUs' joint evaluation of lessons learned on undergrounding applications. These lessons learned must include use of resources (including labor and materials) to accommodate undergrounding programs, any new technologies being applied to undergrounding, and cost and associated cost effectiveness efforts for deployment.

Lessons learned regarding undergrounding have been discussed among the Joint Utilities during quarterly meetings held throughout 2024. The following lessons learned were noted in those discussions:

1. Managing resources requires a clear understanding of the scope of work and overall workplan to ensure the appropriate allocation of internal resources versus contractors. Ensuring the right resource balance between the two can optimize cost and efficiency.

2. Continuing to test and deploy new technologies is an effective way to improve productivity and reduce unit costs, particularly when paired with innovative construction approaches.
3. Proactive planning was identified as important, particularly in identifying potential challenges, such as encountering hard rock, that can significantly impede construction progress and contribute to cost overruns.

Each of these lessons learned could lead to revised practices that will minimize delays, cost overruns, and resource inefficiencies. To reinforce the need to improve upon these areas, the Joint Utilities continue to discuss these topics regularly.
In late 2023, PG&E and SDG&E participated in a 2-day EPRI workshop with over 10 utilities from across the United States to discuss electrical undergrounding programs and lessons learned. The workshop covered key challenges as well as solutions and best practices on a variety of undergrounding topics. Key challenges identified by workshop participants included:

- Obtaining easements and permits
- Geological challenges, such as granite and sand hills
- Paving requirements and coordination with local governments
- Material supply chain delays
- Managing project cost

Workshop participants explored solutions and lessons learned, including:

- Less invasive trenching (including shallow trenching and micro-trenching)
- Comprehensive contract bidding
- Best practice collaboration and communication with local government and permitting agencies
- Standardizing material components to simplify design, purchasing and installation

In April 2024, PG&E published its benchmarking study that evaluated 11 electric utility strategic undergrounding programs[230]. Strategic undergrounding programs are defined as those in which the utility chooses electric assets to underground with a goal of mitigating safety, reliability, or other risks. The participating utilities represent geographic regions across the United States and have strategic undergrounding programs in various stages of development. Collectively, these utilities serve more than 60 million customers.
The purpose of this undergrounding benchmarking study was to learn how different utilities across the United States are approaching strategic undergrounding in their service territory and to identify trends and lessons learned. Overhead system hardening programs were not addressed in the study. Participating utilities responded to an online survey and participated in follow-up phone interviews. The study focused on the following issues: (1)

[230] The 11 participants include PG&E and two other California electric utilities.

the scale and scope of undergrounding; (2) utilities' motivation to underground and site selection approach; (3) costs and cost containment; (4) customer engagement; and (5) technical standards and operations.
Key takeaways and lessons learned included

- Scale and scope of undergrounding programs
  - Participating utilities' programs vary in scale, from established programs that have converted more than 1,500 overhead miles to underground to small pilots
  - Most utilities are undergrounding primary distribution lines, secondary distribution lines, and service lines, although some are pursuing alternative strategies such as installing more resilient poles and equipment, vegetation management, and operational mitigations, including power shutoffs.
- Motivation and site selection
  - Utilities in the South and Midwest cited reliability and/or resilience to weather events as their main motivations for strategic undergrounding. Utilities in the West primarily use their undergrounding programs to reduce wildfire risk.
  - Utilities selected sites based on metrics related to their motivation for pursuing strategic undergrounding: reliability metrics in the South and Midwest and wildfire risk in the West.
- Cost and cost containment
  - Unit costs are highly variable and are affected by factors such as terrain and population density. On the whole, Southern and Midwestern utilities see lower costs than Western utilities.
  - Several utilities noted negative impacts resulting from a constrained supply of pad mount transformers in the second half of 2023.
  - Utilities noted that economies of scale (e.g., contracting, design, and workforce considerations) have helped contain costs.
- Customer engagement
  - Utilities noted that obtaining easements can be challenging, but customer outreach and education can help.
- Technical standards and operations
  - Depth and method of cover above the undergrounded lines were fairly standard across utilities surveyed, at 30 to 36 inches, and most utilities pull cable through conduit rather than direct burying electric cables.

The report is publicly available here: https://www.pge.com/assets/pge/docs/outages-and-safety/safety/undergrounding-benchmarking-report.pdf
Use of resources (including labor and materials) to accommodate undergrounding programs
Materials supply chain issues were identified as key challenges by a number of the utilities in the PG&E's benchmarking study. Limits on the availability of key materials can stop or slow construction work and delays can increase project costs. For example, three utilities with established strategic undergrounding programs commented that a limited supply of pad mount transformers presented challenges and/or caused delays in their undergrounding programs during the second half of 2023; two of those utilities highlighted supply chain issues as the top challenge facing their programs. In addition, two utilities with undergrounding programs in the pilot stage reported that supply chain issues challenged their programs.
Effective management of labor resourcing has been a topic discussed in quarterly meetings. Utilities have shared lessons learned regarding how unproductive time can create cost challenges for a program and how schedule management and use of labor resources can help alleviate this issue. For example, utilities discussed the importance of managing contract resources to align with the timing and scale of planned work and to be able to offboard contract labor when scheduled work is decreased or delayed due to weather or other conditions.

New technologies being applied to undergrounding

The Joint Utilities are evaluating Ground Level Distribution Systems (GLDS), which may provide an alternative to traditional underground systems. This technology involves installing facilities at the ground level, removing the need to bury the cable in areas where difficult terrain that makes traditional undergrounding infeasible.
PG&E's Undergrounding Innovation team identifies new undergrounding technologies to understand their potential effectiveness and value to the program. Examples of new technologies PG&E is applying to its undergrounding program include:

- **Fluid Free Boring Technologies**: While horizontal directional drilling (HDD) is a valuable installation method, disposal of the resulting large quantities of mud presents cost and logistical challenges in remote areas. PG&E is pursuing multiple technologies that reduce or eliminate the production of mud as a result of drilling.

- **Automated Utility Design**: New smart design tools can be used to calculate characteristics such as voltage drop, cost, and parts needed on the fly as a design is created. By using this software to calculate these characteristics, cycle times and errors that would require design rework can be reduced.

- **Spider Plow**: This installation method for rough terrain can install multiple conduits without the need for an excavated trench, even when an area can only be accessed by bulldozer. Spider plow can efficiently install reels of conduit in terrain that would be high cost for conventional means of construction.

- **Augmented Reality (AR) Tools**: These tools can create more transparency with customers by providing three-dimensional visuals of work that will take place on a customer's property. This transparency provides greater understanding of the undergrounding work and the end result, improving the customer experience and reducing the need for redesigns.

SDG&E

SDG&E is evaluating various technologies to enhance the efficiency of wildfire mitigation. These technologies aim to strengthen fire prevention efforts, improve situational awareness, and enhance response capabilities in high-risk areas. For example:

1. GLDS: SDG&E is exploring the use of GLDS, ideal for areas where underground conversions are difficult, such as rocky terrains, environmentally sensitive regions, or challenging field conditions. This technology features durable above-ground trays that hold distribution conductors and are then encased in epoxy resin concrete for added resilience. To evaluate the effectiveness of GLDS in various scenarios, SDG&E plans to construct a test setup and conduct a pilot project. SDG&E is partnering with the Electric Power Research Institute (EPRI) to further test this technology.

2. Mobile application for improved communications with property owners: SDG&E is exploring the use of mobile applications to enhance communication with property owners. Through the use of artificial intelligence and machine learning, property owners can view an augmented reality visual representation of how their property will look after the installation of electric equipment such as transformers or junction boxes. This technology will give property owners a better understanding of the impact of installed equipment during an underground conversion project, helping them make more informed decisions about granting easements to the utility.

3. Improved process for handhole installation in high altitude areas: When above surface land rights and/or geography limits the ability to install padmounted structures, sub surface handholes are installed. To prevent collisions between handhole covers and snowplowing vehicles in high-altitude areas, particularly on unpaved county roads, SDG&E has successfully implemented a new handhole installation method utilizing soil stabilization materials. This approach enhances the

durability of handholes while protecting both the covers and snowplowing equipment.

4. Microgrids: SDG&E is evaluating microgrid solutions as an alternative to overhead power lines, particularly for circuits that serve minimal loads like well pumps or antennae. If a load analysis confirms that the microgrid can reliably support these applications, SDG&E considers removing the overhead lines, reducing wildfire risk and infrastructure maintenance needs.

For SCE, refer to the ground level duct system, referenced in Chapter 8 of the 2026-2028 Base WMP.

2.3.3 Cost and associated cost effectiveness efforts for deployment

A key finding from the PG&E benchmarking study was that unit costs are highly variable and are affected by factors such as terrain and population density. Unit cost information shared by seven utilities with established strategic undergrounding programs was analyzed.[231]Multiple utilities reported that undergrounding costs can vary widely from project to project, and ranges given for a “typical” project may not capture the full variability. The seven utilities reported typical undergrounding unit costs that varied from approximately $300,000 to more than $3 million per overhead mile removed (all costs are presented in 2023 USD). Costs may have limited comparability across and even within utilities because indirect costs may be allocated differently by different utilities, costs differ by the type of asset being undergrounded[232] and method of construction,[233] and smaller, more nascent programs may face higher costs than larger, more established programs.[234] Other themes that drive cost variation include:

- **Terrain**. Four utilities noted that terrain features including hard rock, flood plains, water crossings, or soil type can affect ease and cost of construction. One utility noted that encountering unanticipated hard rock can increase costs because the project cannot be executed as originally designed. When asked to rank the top challenges facing their strategic undergrounding programs, five[235,236] utilities ranked physical topography among the top two.

[231] Because smaller or pilot programs unit cost estimates are based on at most a few completed miles, they were not included in this analysis. In addition, one utility with an established program declined to share unit cost estimates.
[232] For example, one utility noted that the cost of undergrounding a single-phase line was approximately 40 percent lower than that of undergrounding a 3-phase line, and that a 3-phase, large conductor line cost approximately 30 percent more to underground than a standard 3-phase line.
[233] For example, as noted by one utility, directional boring had higher costs than trenching.
[234] Programs in the pilot phase are excluded from this analysis due to the potential for higher costs than established programs.
[235] The utility that did not report its unit costs is included in this analysis.
[236] Including PG&E.

- **Population density and customer load base**. Two utilities noted that undergrounding costs are higher in more densely populated areas, and a third noted higher costs in areas where customer load base is higher. A fourth utility noted that the need to obtain more easements can drive project costs up and that the use of existing easements where possible can help contain costs.

- **Region**. Typical undergrounding unit costs varied between $300,000 to less to $1.7 million per overhead mile removed among Southern and Midwestern utilities. Western utilities[237] reported costs to date generally varied from $2.0 to $3.7 million per overhead mile removed, but one projected that future costs could rise to as much as $4.6 million per overhead mile removed.

The eight utilities with established strategic undergrounding programs[238] were asked about strategies they have used to contain costs. Common themes included:

- ***Building economies of scale.*** Three utilities[239] noted that they achieved cost efficiencies by undergrounding adjacent or nearby segments simultaneously or in sequence. They also discussed finding cost efficiencies through larger-scale purchases or longer-term contracts or providing contractors with a consistent level of work to enable them to maintain a steady workforce level.

- ***Unit pricing and other contract considerations.*** Five utilities described contracting approaches that have helped contain costs. Two reported signing turnkey, unit-priced contracts with vendors. A third reported it is moving toward fixed pricing and currently limits change orders. A fourth noted that it is negotiating construction allowance agreements to limit unanticipated costs. A fifth noted that competitive bidding has generally helped drive undergrounding costs down. One utility further noted that it tracks contractor performance metrics such as on-time completion of work.

- ***Design considerations.*** Six utilities[240] noted that efficient or careful system design, exploring alternative design options, and ensuring design-build alignment can help contain costs.

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237 Including PG&E.
238 Utilities included were those with large or moderately-sized programs, including the utility that did not share unit costs.
239 Including PG&E.
240 Including PG&E.

- ***Depth of cover and method of trenching.*** Two utilities noted that they have reduced depth of cover (also referred to as trench depth) where possible as a cost containment strategy; another noted that shallower trenches could work in some locations and was in the process of piloting this strategy.[241] A fourth utility reported that its use of directional boring, rather than trenching, may increase costs.

- ***Workforce.*** Two utilities noted the importance of maintaining a qualified skilled workforce to contain costs. Two utilities reported using a project management office to oversee the end-to-end undergrounding process and to identify process efficiencies.

Topic #3: Protective Equipment and Device Settings

The IOUs' joint evaluation of various approaches to implementation of protective equipment and device settings. This evaluation must include an analysis of the effectiveness of various settings, lessons learned on how to minimize reliability impacts and safety impacts (including use of downed conductor detection and partial voltage detection devices), variations on settings used by IOUs including thresholds of enablement, and equipment types in which such settings are being adjusted.

Beginning in 2019, the Joint Utilities met regularly to discuss various electrical protection and sensor-based methods to mitigate wildfire ignition risk and to exchange lessons learned. Topics of discussion included various protective equipment and device settings deployed by the Joint Utilities. The initial participants were PG&E, SCE, and SDG&E. Meetings have since expanded to include Liberty Utilities, and most recently, PacifiCorp. The following sections provide a comparison of the various protective equipment and device settings the Joint Utilities have implemented to reduce the risk of wildfire ignitions from utility equipment and mitigate reliability impacts.

Effectiveness of various settings

PG&E

EPSS program effectiveness for the years 2021 to 2023 was calculated by comparing the reduction in ignitions when EPSS is enabled to a baseline timeframe before the Dixie Fire (2021) when EPSS would have been enabled in the same conditions.

Based on this analysis, PG&E found an ignition reduction effectiveness of 74.1 percent in 2021, 68.8 percent in 2022, and 72.7 percent in 2023. In 2024, PG&E adopted a Stratified

[241] While data on depth of cover was collected from the majority of participating utilities, due to small sample size and the number of other factors that vary between utilities, a clear pattern relating cost and depth of cover did not emerge across participants.

Effectiveness methodology to understand EPSS effectiveness in reducing the rate of overall ignitions. The current calculated effectiveness based on the new FPI-stratified effectiveness formula is 65.2 percent.

This analysis is explained in greater detail in Section 8.7.1.1 of PG&E's 2026-2028 WMP.

SCE

SCE began using Fast Curve Settings (FCS) in 2018. In June 2022, SCE refined its FCS program for application to new and existing installations. FCS is applied in conjunction with recloser relay blocking, which prevents the automatic closing of circuit breakers and remote automatic reclosers following a relay/trip operation. The combined effectiveness of FCS and recloser relay blocking for the years 2021 to 2023 was estimated comparing ignition event frequencies of SCE circuits. Please see Sections 8.2.8 and 8.7.1 of SCE's 2026-2028 WMP for information on setting effectiveness.

SDG&E

SDG&E completed a study to determine the impact of sensitive relay settings at reducing ignitions from risk events downstream of SRP enabled devices. SRP device enable history was examined against the risk events and ignition data from 2015 to 2024, and found zero ignitions by primary faults downstream of devices with sensitive relay settings enabled. This study was detailed in SDGE's 2020-2022 WMP and is updated on an annual basis.

Lessons learned on how to minimize reliability impacts and safety impacts (including use of downed conductor detection and partial voltage detection devices)

Downed Conductor Detection (DCD)

PG&E

DCD technology could improve the ability to detect and isolate high impedance faults before an ignition can occur. PG&E first deployed DCD in 2022 as a pilot that provided an additional protection element to address fault types not yet fully mitigated through the EPSS program. This additional protection is achieved by enhancing the ability to quickly detect and de-energize low and very low initial current (high-impedance) line-to-ground faults before an ignition can occur, which is the primary existing gap in EPSS protection on primary overhead distribution conductors.

During EPSS, DCD is enabled if the device is DCD capable. This feature is highly sensitive, which allows the detection of high-impedance ground faults. However, due to its sensitivity it cannot be coordinated between devices in series. In response to unintended false positive trips with DCD settings, PG&E upgraded the firmware on existing DCD devices to improve the high-impedance fault detection accuracy, which reduced nuisance outage frequency. By the end of 2024, over 500 devices have received updated firmware to improve performance. PG&E will continue to upgrade firmware on remaining DCD devices during the 2026-2028 WMP cycle.

SCE

SCE is refining the fast curve settings but generally is seeing this in a steady-state without major changes since the settings update around the 2022-2023 time period.

SDG&E

As discussed in ACI SDGE-25U-05, SDG&E performed an efficacy study on EFD devices, which found that the initial settings of EFD detected many underground faults. Moving forward, EFD algorithms will be fine-tuned to further focus on the detection of overhead incipient faults. See SDG&E's 2026-2028 Base WMP Appendix D for details on ACE SDGE-25U-05.

Partial Voltage Detection Devices

PG&E

To support PG&E's identification and response to high-impedance faults, new data-driven capabilities leveraging the SmartMeter™ network have been implemented. Partial Voltage (PV) Alerts target the 3-wire distribution system with Line-to-Line connected transformers and indicate low SmartMeter Voltage (25 to 75 percent of nominal 240 V).

If partial voltage conditions are detected, Control Center Operators can force out, remotely or locally manually opening a switch or protective device to de-energize the line downstream, an upstream Supervisory Control and Data Acquisition (SCADA) device at the location where multiple partial voltage alarms are received. When a partial voltage alarm indicates low SmartMeter™ voltage on two or more SmartMeter™ devices at the fuse level, the Distribution Control Center Operator can open the next upstream 3-pole gang-operated SCADA device and dispatch response teams to the area of the alarm.

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, reducing the possibility of an ignition. If an ignition does occur, first responders are able to locate and extinguish it more quickly. A total of 86 partial voltage force outs occurred from 2022 to 2024. These were largely triggered by vegetation or animal contact, which are common fault types that trigger ignitions.

SCE

SCE uses its smart meter voltage alerts and other data sources to identify abnormal circuit conditions and acts to either de-energize circuitry or dispatch crews for further investigation. Meter Alarming for Downed Energized Conductors (MADEC) is a machine learning algorithm utilizing smart meter data to detect a subset of energized wire-downs and other high impedance faults/hazards and generates an alarm that allows an operator to act quickly and de-energize the circuit. MADEC is currently being used throughout SCE's service territory. The MADEC system works for both bare wire and CC applications. The MADEC system can limit the total time a downed conductor stays energized after falling, providing potential reduction of ignition risk and public safety benefits.

SCE additionally applies algorithms using voltage data from smart meters can detect small voltage rises associated with shorted turns in the transformer. These algorithms can identify early signs of transformer degradation, to allow proactive equipment replacement prior to complete failure.

Smart meter voltage alarms are also used to dispatch SCE crews to investigate causes of abnormal conditions often helping improve response times to circuit events that may impact customer reliability. Examples of these conditions are transformer or branch line fuse operations that create customer electric service interruptions.

SDG&E

To support the identification of high impedance faults not tripped by other protective devices, SDG&E has developed a partial voltage detection platform that uses AMI 1.0 voltage readings to determine if there is an active downed wire within minutes. The tool is currently being evaluated by the engineering group for correctness and adjustment to the algorithms. Upon operationalization, this tool will act as a last line of defense to reduce the amount of time a downed line is energized, which will reduce the safety risk to the public and reduce the possibility of the downed conductor causing an ignition. If an ignition does occur, the location will be easily identifiable, allowing first responders to extinguish it more quickly.

Variations on settings used by IOUs including thresholds of enablement and equipment types in which such settings are being adjusted

	PG&E	**SCE**	**SDG&E**
Settings Program Name	Enhanced Powerline Safety Settings (EPSS)	Fast Curve (FCS) Settings	Sensitive Relay Profile (SRP) and Sensitive Ground Fault (SGF)
First Deployed	2021	2018	2011
Scope	HFTD, HFRA, and non-HFTD Buffer Zones	HFRA	HFTD and non-HFTD
Equipment Types in Which Such Settings are Being Adjusted	Circuit breakers Line Reclosers Interrupters Fuse Savers	Distribution circuit breakers Remote controlled automatic reclosers	Some feeder circuit breakers starting in 2025 Line reclosers
Enablement Criteria	In the HFTD and HFRA EPSS is always enabled during peak season on days with a rating of R2 and above, and under certain R1 and R2 conditions during Non-Peak Season: During Peak Season: *R1*: EPSS is enabled if wind speed is >19 mph, relative humidity is <75%, and dead fuel moisture is <9%	FCS are enabled in conjunction with automatic recloser relay blocking. FCS are enabled by using EMS and DMS group controls during the following conditions: • Red Flag Warning issued by the National Weather Service • Fire Weather Threat declaration made by SCE Weather Service	SRP and SGF are enabled when extreme fire weather conditions or PSPS de-energizations are forecasted.

	PG&E	SCE	SDG&E
	During Winter Posture (Non-Peak Season): *R1*: EPSS is enabled if wind speed is >25 mph, relative humidity is <20%, and dead fuel moisture is <9% *R2*: EPSS is enabled if wind speed is >22+ mph, relative humidity is <25%, and dead fuel moisture is <9% In EPSS Buffer Zones: EPSS enabled during FFW/RFW / mFPC / PSPS adjacent conditions	• Fire Climate Zone declaration made by SCE Weather Service • Thunderstorm Threat declaration made by SCE Weather Service	
Note: RFW = Red Flag Warning, FWW = Fire Weather Watch, mFPC = Minimum Fire Potential Conditions			

Topic #4: New Technologies

The IOUs' continued efforts to evaluate new technologies being researched, piloted, and deployed by IOUs. These efforts must include, but not be limited to: REFCL, EFD, distribution fault anticipation (DFA), falling conductor protection, use of smart meter data, open phase detection, remote grids, and microgrids.

REFCL

The Joint Utilities evaluated the distribution network for applications of REFCL technology to aid with wildfire mitigation efforts.

SCE

See the main discussion on REFCL in chapter 8 of SCE's 2026-2028 WMP.

PG&E

PG&E continues to evaluate performance of REFCL as implemented at the Calistoga substation. In 2025, PG&E will be assessing an additional site for potential REFCL installation that is aligned with the broader underground and overhead hardening strategy for substations located in the HFRA.

SDG&E

SDG&E does not employ REFCL. SDG&E performed a REFCL study from 2020 to 2021. The purpose of the study was to identify the requirements, costs, and benefits of implementing a REFCL scheme at a single transmission-distribution substation feeding 3 distribution circuits in Tier 3. Results of the study showed that the cost to implement REFCL was too significant considering the need for distribution circuit and substation rebuilds. See SDG&E's 2022 WMP Update, Section 4.4.2.10 for details on the full study.

EFD

SDG&E

SDG&E's Early Fault Detection (EFD) Program utilizes two independent technologies to detect incipient faults on the system, with the goal of providing sufficient time to locate and potentially fix or replace equipment prior to it permanently failing. Incipient faults occur on aging and failing pieces of equipment typically long before they fail, sometimes violently, potentially causing damage to the surrounding area.

In 2024, the EFD program focused efforts on developing and optimizing processes and procedures to enable repeatable results and increase production capacity. Key milestones included:

- Revising and publishing overhead construction standard (OHCS) 743. This standard was also converted to a 3D model, allowing users to fully visualize installation best practices.
- Drafting construction standard (UG 7665), which is expected to be published in 2025. Design of ARFS on pad mounted transformers was paused until the standard is fully published.
- Developing a solar assembly for ARFS, enabling installation of sensors at locations where potential transformers did not already exist, and installation of new transformers would be too difficult or cost prohibitive.

In 2025 SDG&E will test a smaller and more cost effective ARFS solution that does not require a full engineering design cycle, rarely requires pole replacements, and is connected directly to the low voltage side of existing transformers using insulation penetrating connectors (IPC). If successful, the program has the potential to quickly increase sensor density and speed of deployment. Additional PQ meters will also be installed on distribution assets, which will increase incipient fault awareness.

PG&E

PG&E has installed EFD sensors on eight distribution circuits (203 locations) in Tier 2 and Tier 3 of the HFRA that are being used to proactively detect incipient equipment conditions. EFD uses the capture of partial discharge events (micro arcing) to detect and isolate early-stage equipment failures, including degrading/damaged conductor, cracked/damage/loose insulators, failing splices, and vegetation encroachment. PG&E is planning on installing approximately 180 sensor locations per year in the 2026-2028 WMP cycle.

DFA

SCE

Between 2019 and 2021, SCE installed 215 DFA units for monitoring HFRA circuits. DFA is a standalone device that is intended to anticipate system failures, although the use of data from other systems can help diagnose or locate some of the alerts from the system. These other systems include Advance Metering Infrastructure (AMI) and Intelligent Electronic Device (IED). Early identification of pre-fault or pre-failure electrical signatures can allow maintenance to be conducted prior to a larger electric system event, helping to reduce ignition or other risks. SCE applied a product from Texas A&M for its DFA applications, however other types of fault recorders or power quality meters could potentially be configured to provide similar capabilities. This technology is presently using traditional voltage and current transformers for collecting measurements. In many cases existing voltage and current transformers at the substation can be configured to these data acquisition systems, helping limit total installation cost.

PG&E

PG&E installed DFA sensors at substations on 96 circuits in Tier 2 and Tier 3 of the HFRA. DFA sensors in combination with Line Sensors, Line Reclosers, SmartMeters, and an in-house Foundry based analytical platform are being used to preemptively detect and isolate latent sources of unknown caused outages to remove the risk of outage recurrence during high wildfire risk periods. PG&E is planning on installing 15 additional circuits each year in the 2026-2028 WMP cycle.

Falling conductor protection

PG&E

As discussed in ACI PG&E-23-07 in PG&E's 2025 WMP Update, falling conductor protection (FCP) is defined as a protective scheme that attempts to de-energize a broken wire before it contacts the ground (or shortly thereafter) to prevent an ignition. This scheme requires sensing devices and communication links, which can be difficult to implement at scale on a distribution system in highly forested terrain. Additionally, to be effective circuit-wide, every lateral branch of the circuit would need a sensing device at the end of the line to be able to detect broken wires before or shortly after they contact the ground, which would be cost prohibitive. Finally, the majority of CPUC-reportable ignitions within HFRA portions of PG&E's service territory occur because of vegetation contact or other external contact, which FCP cannot always mitigate.

However, in certain strategic and high-risk locations, it may be possible to implement a FCP scheme to provide coverage for a targeted section of distribution overhead circuitry. PG&E is currently in the early stages of a pilot initiative to attempt to provide FCP online reclosers over existing cellular connectivity to determine the overall feasibility of this type of solution. Lessons learned, such as cellular connectivity latency, device compatibility, and ignition mitigation effectiveness, will be evaluated as part of this effort.

In the meantime, PG&E will continue to leverage and expand the EPSS program to mitigate distribution falling conductor related ignitions. This program also includes an algorithmic based high impedance ground fault DCD capability and SmartMeter partial voltage detection to mitigate distribution wire down-related ignitions.

SDG&E

SDG&E's Advanced Protection Program (APP) develops and implements advanced protection technologies within electric substations and on the electric distribution system. The program aims to prevent and mitigate the risks of fire incidents, provide better distribution sectionalization, create higher visibility and situational awareness in fire-prone areas, and allow for the implementation of new relay and automation standards in locations where protection coordination is difficult due to lower fault currents attributed to high impedance faults.

The program upgrades and installs protection equipment and devices capable of supporting FCP technology, which trips one or more zones of protection on overhead distribution circuits before broken energized conductors can reach the ground. When an energized conductor fails due to normal aging, over-stressed conditions, or other reasons, the conductor may continue to be energized as it falls and when it reaches the ground. If the conductor makes physical contact with other objects as it falls, arcing may occur, which could result in sparks or embers being distributed across the adjacent area. If the conductor is energized when it reaches the ground, the same type of arcing and subsequent ignition may occur. The risk of falling CCs, while minimized by the insulation surrounding the length of the cable, may result in a high impedance fault at the failure point that could go undetected by protection equipment, creating a potential for ignition. FCP is compatible with traditional open and CC cable and provides the same risk mitigation benefits to both.

SDG&E implements FCP by using a combination of substation protective relays, distribution reclosers, and line monitoring equipment that are in constant communication via high-speed wireless data connections. All devices send readings at 30 samples per second to a centralized real-time automation controller (RTAC) located in the substation. The RTAC consolidates the data and uses multiple algorithms to determine whether a falling conductor condition exists, where it is located, and what section(s) of the circuit must be deenergized. A typical conductor takes approximately 1.4 seconds to reach the ground when it falls; the system is capable of detecting, reacting, and deenergizing a conductor in less than 700 milliseconds (0.7 seconds).

Cost of FCP deployments varies due to multiple factors. Substation circuit breakers, relays, and remote terminal units may require replacement to support FCP. Expulsion fuses may need to be replaced with reclosers, and line monitoring equipment must be installed at the end of each protected branch. High speed data communications must exist or be installed, and poles may need replacement to support the additional weight of reclosers and line monitor equipment. To reduce the total cost of construction, SDG&E is exploring emerging single-ended FCP detection technology, which may reduce the required number of devices. EFD ARFS coverage will also be included on circuits targeted for FCP to determine which technology provides the best risk reduction. FCP will typically cover the main feeder and branches of the circuit and EFD will typically cover remote branch sections too cost prohibitive to deploy FCP.

Smart meter data

SCE

Smart meters provide large quantities of data, and when coupled with other data can help alert SCE of inspection needs or other actions. Smart meter data is coupled with GIS system data and historical event data to help detect possible wire down situations where the conductor may remain energized. SCE calls this Meter Alarming for Downed Energized Conductor (MADEC). When a MADEC alarm is identified, SCE manually de-energizes the line to help reduce ignition and other public safety risks. SCE also uses smart meter data to help detect defects that lead to failures in distribution transformers. Winding shorts, partially turn-to-turn shorts, create small increases in voltage on a transformer secondary that can be detected by smart meters. By aggregating and comparing voltage data of surrounding transformers, SCE can create replacement maintenance actions for some transformers prior to failure. This helps reduce ignition risks due to equipment failure and also helps limit the effects of electric service outages to customers. SCE continues to explore other possibilities for the use of meter data to help manage operation and maintenance of the distribution electric system.

PG&E

Similar to SCE's MADEC, PG&E uses SmartMeter partial voltage detection alerts to inform operators of possible down conductor conditions. PG&E also uses SmartMeter interval voltage data and machine learning algorithms (IONA) to detect secondary and transformer high risk conditions including service transformer windings failures, overloaded transformer, and secondary service connection issues. Additionally, next generation SmartMeters are currently being piloted to see if high resolution edge computing sensor devices improve visibility and alerting of secondary voltage conductor conditions issues including, splice/connection issues, conductor insulation deterioration, vegetation contact, and transformer early-stage failures.

Open Phase Detection

SCE

Open phase detection/protection (OPD), sometimes referred to as falling conductor and broken conductor detection/protection, focuses on de-energizing powerlines when a separation is detected with sufficient speed to de-energize the line before it makes contact with the ground. Transmission and Distribution system topologies and relaying strategies have led to differences in how open phase detection can be applied.

Downed powerlines that remain energized create a risk of ignition when arcing proximate to fuels. Various conditions, such as car collisions with poles, falling vegetation, mechanical impacts, failure of conductor supports, and arcing associated with electrical faults can create open phases. Additionally, a conductor may remain intact in some situations but can still fall to the earth, for example when a car hits a pole, or a large tree and damages crossarms and/or poles without causing a wire separation.

Distribution systems schemes rely heavily on voltage measurements to determine the normal and operational conditions. Radio communication, which requires remote measurements at the end of the protection zone, is the preferred choice for voltage monitoring. Operating times of approximately one second are needed to sufficiently detect an open phase event and de-energize a line section. The demands for speed and bandwidth of the radio system are within present technology capabilities. Current common practice is to have 900 Megahertz (MhZ) radio networks to support traditional distribution automation schemes, which may not have the needed speed or bandwidth to reliably apply an OPD scheme.

SCE's mainline distribution OPD will typically focus on larger conductor sizes and can encompass multiple miles of conductor. The costs for monitor voltage at one end point compared to total conductor length will generally be lower than multiple voltage measurement points needed to monitor tapline locations. While it is generally expected that a smaller conductor is more prone to experiencing a downed wire event, both large and small conductors can experience separation or failure.

For transmission systems, OPD schemes have focused on current measurement quantities rather than voltage. Transmission systems may have more than one voltage source that can operate islanded, which traditional radial distribution systems usually do not do. The additional voltage source as well as lack of distributed loads allow current and changes in current to be integrated into protective relays.

PG&E

PG&E leverages SmartMeter Partial Voltage Detection as part of EPSS to mitigate some wire down incidents due to high impedance faults associated with broken conductors. This is not a "falling conductor" scheme in traditionally sense but does provide some level of open phase detection capability to force out a line after some time when the condition occurs. See Section 4.1.4 for more information on Falling Conductor Protection.

Remote Grids

The Joint Utilities continue to use Remote Grid Applications as they help to limit ignition risk exposure for some circuitry or costly upgrades by serving customer loads from a dedicated source rather than the grid. Remote grids must be capable of providing sufficient and reliable power for the customer load that would be islanded with the dedicated generation. In general, these customer loads are relatively small and are in areas where a distribution line may extend a substantial distance as this helps to limit the cost of remote generation grid facilities and helps with reasonability of the comparative risk of traditional electric system upgrades, such as CC or undergrounding of overhead lines.

Microgrids

The Joint Utilities design and build permanent and temporary microgrids that can be electrically isolated during a PSPS event, thereby maintaining electric service to customers within the microgrid boundary. While alternative hardening solutions, such as undergrounding electric lines, may be better at simultaneously mitigating wildfire risk, those options are not always technically feasible or cost-effective.

A combination of data including the risk of wildfire from overhead infrastructure, feasibility of traditional overhead hardening solutions, alternative solutions such as undergrounding distribution infrastructure, and historical PSPS impact data is used to guide the installation of microgrids.

This mitigation focuses on reducing electric service interruptions for customers who would otherwise be affected during PSPS events. The operation of microgrids complements the reduction risk of ignitions caused by electric service lines that are de-energized during PSPS events.

Other-All

SCE

Radio Frequency Defect Detection System (RFDDS) equipment, also called Early Fault Detection (EFD), is applied on SCE's network. SCE has applied sensors to its distribution and sub-transmission networks up to 115 kV. These systems attempt to both detect and provide a location of a defect or undesirable condition on the network. SCE's findings include failing insulators, vegetation contact, broken conductor strands, poor connections, and damaged bond wires. Locating and repairing these types of issues prior to failure can help avoid potential ignition events and improve the integrity of the electric system. Distribution Waveform Analysis (DWA) equipment, also referred to as Distribution Fault Anticipation (DFA), is applied on SCE's distribution system. SCE applies DFA to distribution circuits to monitor performance of the system to better understand the technology functionality and requirements on the SCE workforce to utilize the technology. The alerts from DFA have helped locate faults, particularly for phase-to-phase conductor contact faults. These types of faults can repeat over time and identifying the location and making remediations to the line, like insulated line spacers, can help avoid future outages or ignition events. As part of SCE's trial, SCE also learned about the ability for DFA to help detect failing underground connections or components among other detection conditions. SCE continues to monitor alerts from the existing DFA system and work with the DFA supplier to better understand where DFA can supplement other monitoring systems such as smart meters or RFDDS.

Topic #5: Overall Effectiveness of Mitigation

The IOUs' joint evaluation of the overall effectiveness of mitigations in combination with one another, including, but not limited to overhead system hardening, maintenance and replacement, and situational awareness mitigations. This must also include analysis of in-field observed effectiveness, interim risk exposure during implementation, and how those impact effectiveness for ignition risk, PSPS risk, and outage risk associated with protective equipment and device settings.

Each utility implements the wildfire mitigations and combinations of mitigations that are most suited to that utility's territory and risk factors. The Joint Utilities do not have a single joint evaluation of mitigation effectiveness. However, they meet regularly to benchmark mitigation efforts. Each utility implements the mitigations and combinations of mitigations that are most effective in its own service territory, which can have different effectiveness values depending on the service territory (fuels, topography, weather, etc.) and methodologies used. Each utility describes its mitigation combinations and available mitigation data and effectiveness values in their WMP.

Overall effectiveness of mitigations <u>in combination with one another</u>, including, but not limited to overhead system hardening, maintenance and replacement, and situational awareness mitigations

The Joint Utilities measure the overall results of wildfire mitigation efforts through a combination of evaluation, measurement, and verification practices. For overhead system hardening, the Joint Utilities track the completion of hardening projects, such as replacing wooden poles with steel ones, installation of CC, and undergrounding power lines.
The Joint Utilities track and collect ignition outage and equipment failure data and outage data. Combining system hardening with regular maintenance and timely replacement of aging or damaged equipment is crucial for preventing failures that could spark wildfires.
The Joint Utilities maintain detailed records of inspection and maintenance activities and equipment replacements. Assets are evaluated for effectiveness by analyzing the frequency and severity of equipment-related incidents or by observing equipment damage during regularly scheduled inspection activities. The Joint Utilities continue to measure the collective effectiveness of these mitigations by monitoring the number of incidents and risk event data. Finally, each Joint Utility employs risk modeling to monitor how risk changes with different combination of mitigations.
SDG&E partnered with a third-party to validate individual mitigation effectiveness values and methodologies and explore the impact of combined mitigation strategies, which will help identify the most cost-effective and impactful mitigation approaches. The study's findings indicate that undergrounding of electric lines is the most effective mitigation measure, surpassing other combinations, including CC, FCP, and EFD. SDG&E is currently reviewing the methodology, assumptions, and results of this analysis. This evaluation will help determine whether an update to the existing methodology is necessary.

In-field observed effectiveness

Field crews conduct routine diagnostic testing, as appropriate, and perform regular visual ground inspections and manned and unmanned aerial inspections of power lines, poles, and other infrastructure to identify potential hazards such as damaged equipment, vegetation encroachment, and other risk factors. These inspections help the utilities assess the condition of assets and the effectiveness of maintenance and hardening efforts. The utilities also install monitoring devices such as weather stations, high-definition cameras, and remote sensing technology on electric infrastructure. These devices provide real-time data on environmental conditions, equipment performance, and potential ignition sources. By analyzing this data, the utilities can evaluate the effectiveness of technologies and make informed decisions about necessary interventions. In addition, the utilities regularly gather feedback from field crews who are directly involved in implementing and observing mitigation measures. This feedback helps identify practical strategies to improve mitigation efforts and areas for improvement.

Interim risk exposure during implementation

The Joint Utilities deploy a variety of interim mitigations to reduce system risk until more permanent, long-term mitigations can be fully deployed. The Joint Utilities perform vegetation management throughout their service territories by trimming and removing vegetation around power lines and equipment to help prevent contact that could cause an ignition event. This includes creating defensible spaces (pole clearing). The Joint Utilities proactively utilize PSPS during extreme weather conditions to prevent electrical equipment from igniting wildfires. This measure is used as a last resort when the risk of wildfire is exceptionally high. In addition, the Joint Utilities adjust protective equipment and device settings to reduce the risk for a potential ignition event.

How [in-field observed effectiveness and interim risk exposure during implementation] impact effectiveness for ignition risk, PSPS risk, and outage risk associated with protective equipment and device settings

In-field observed effectiveness and interim risk exposure data is analyzed on a regular basis through various methods, such as modeling and trend analysis, and reevaluated on a regular basis through quarterly and annual updates to each Joint Utility's WMP.
Based on the results of the analyses, modifications are implemented to each Joint Utility's WMP and combinations of mitigations.
More details regarding the results of the analysis and mitigation strategy changes are discussed in each Joint Utility's WMP.

Topic #6: Applications in the WMP

Additionally, PG&E must report on all lessons learned PG&E has applied or expects to apply to its WMP, including a list of applicable changes and a timeline for expected implementation as applicable.

Utility	Lessons Learned	Changes in the Utility's WMP
PGE	Topic 1: CC	Reference Section 8.2.1 in PG&E's 2026-2028 WMP
PGE	Topic 2: Undergrounding	Reference Section 8.2.2 in PG&E's 2026-2028 WMP
PGE	Topic 3: Protective Equipment and Device Settings	Reference Section 8.7.1.1 in PG&E's 2026-2028 WMP
PGE	Topic 4: New Technologies	Reference the following Sections in PG&E's 2026-2028 WMP: REFCL–8.7.1.3.1 DFA/EFD–10.3 FCP/SmartMeter Data/ OPD–8.7.1.1 Remote Grids–8.2.7.1 Microgrids–8.2.7
PGE	Topic 5: Overall Effectiveness of Mitigations	Reference Section 5 and Section 6 in PG&E's 2026-2028 WMP
SCE	Topic 1: CC	Reference Sections 5.2.1.2 and 8.2.1 in SCE's 2026-2028 WMP
SCE	Topic 2: Undergrounding	Reference Sections 5.2.1.2 and 8.2.2 in SCE's 2026-2028 WMP
SCE	Topic 3: Protective Equipment and Device Settings	Reference Sections 8.2.8, 8.7, and 10.3.1.5 Protective Relays: Fast Curves in SCE's 2026-2028 WMP
SCE	Topic 4: New Technologies	**For REFCL, r**eference Sections 8.2.6.1 and 10.3.1.8 Fault Current Limiters: (SH-17 & SH-18)and Table 8- 1 Targets in SCE's 2026-2028 WMP **For EFD,** reference Section 10.3.1.1 Radio Frequency Monitors: Early Fault Detection (EFD) (SA-11)and Table 10-1 Target in SCE's 2026-2028 WMP **For MADEC,** reference Section 10.3.1.6 Smart Meters: MADEC & Transformer EDD in SCE's 2026-2028 WMP

Utility	Lessons Learned	Changes in the Utility's WMP
		For DOPD/TOPD, reference section 10.3.1.3 Protective Relays: Distribution Open Phase Detection (DOPD)(SA-14) and 10.3.1.2 Protective Relays: Transmission Open Phase Detection (TOPD)in SCE's 2026-2028 WMP **For Microgrids,** reference Section 8.2.7 in SCE's 2026-2028 WMP **For Remote Grids,** reference Section 8.2.9 in SCE's 2026-2028 WMP
SCE	Topic 5: Overall Effectiveness of Mitigations	Reference Section 6.1.3 Table SCE 6-01 and Section 6.2.1 Table 6-3 in SCE's 2026-2028 WMP
SDGE	Topic 1: CC	Lessons learned include the importance of capturing complete lifecycle costs for CC. See Section 6.1.3 of the 2026-2028 Base WMP
SDGE	Topic 2: Undergrounding	Lessons learned from the grid hardening working group are included in Table 13-1 of the 2026-2028 Base WMP
SDGE	Topic 3: Protective Equipment and Device Settings	Lessons learned include an efficacy study that showed sensitive relay settings eliminate the occurrence of ignitions in the event of a fault on electric lines. See the efficacy study in Section 8.7.1.1 of the 2026-2028 Base WMP
SDGE	Topic 4: New Technologies	For EFD lessons learned, see ACI SDGE-25U-05 in Appendix D of the 2026-2028 Base WMP
SDGE	Topic 5: Overall Effectiveness of Mitigations	SDG&E partnered with a third-party to validate individual mitigation effectiveness values and methodologies while also exploring the impact of combined mitigation strategies. See Section 6.1.3.3.5 of the 2026-2028 Base WMP for lessons learned.

F4 – ACI SCE-23B-17 Enhanced Clearances

Investor-Owned Utility Effectiveness of Enhanced Clearances

March 20, 2025

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1 Executive Summary

Vegetation management is essential for maintaining the safety and reliability of electric power lines, particularly in wildfire-prone areas. By regularly clearing trees, shrubs, and other vegetation around power lines, utilities can reduce the probability of vegetation contact-caused outages ("outages"), consequently resulting in fewer ignitions.

California Public Utilities Commission (CPUC) General Order (GO) 95, Rule 35 mandates a minimum radial clearance of bare line conductors from vegetation, based on conductor voltage and whether facilities are located within the High Fire Threat District (HFTD). Rule 35, Appendix E recommends utilities establish greater clearances at time of pruning to ensure compliance with minimum clearances until the next scheduled maintenance. To reduce the risk of vegetation contact, utility tree pruning practices may exceed the recommended clearances at time of pruning, depending upon location, species, growth rate, tree health, and other site- and tree-specific conditions. To ensure the effectiveness of vegetation management activities in support of wildfire mitigation solutions, three electric investor-owned utilities (IOUs) in California: San Diego Gas & Electric Company (SDG&E), Pacific Gas and Electric Company (PG&E), and Southern California Edison Company (SCE) (collectively the "IOUs"), leverage both quantitative studies and expertise derived from field observations to better understand and improve vegetation management practices.

A study conducted by the third-party company, Electric Power Research Institute (EPRI),[242] evaluated the effectiveness of the clearance at the time of the pruning. This study standardized data from the three IOUs and compared the average duration from the time of inspection or pruning activity to the time of outage, based on the range of clearances at the time of inspection or pruning.

This white paper focuses on quantifying whether enhanced radial clearances are associated with a lower probability of vegetation contact. A machine learning technique, logistic regression model, was used to perform a sensitivity analysis comparing the differences in outage probabilities before and after modifying the targeted enhanced clearance levels. The result indicates enhanced clearances reduced approximately 20% of vegetation-caused outages. This white paper also addresses other factors, beyond radial clearances, that impact outage probabilities. Exploratory data analysis was also employed to identify the unique characteristics of three IOUs' land cover types, assess the impacts of weather conditions during and throughout the year, compare performance outcomes in the HFTD with other regions. Historical radial clearances of trees sampled from SDG&E were also analyzed to quantify the differences in the average outage rates for trees with enhanced clearances.

These different methods have shown that enhanced clearances reduce the probability of vegetation-caused outages by a measurable amount. This reduction in outage frequency can subsequently result in a lower incidence of ignitions in regions characterized by fire-prone vegetation.

However, the effectiveness of enhanced radial clearances in reducing the likelihood of ignitions is limited. Weather conditions can be a direct contributing factor to the probability

[242] This third-party study can be found in SDG&E's 2026-2028 Base WMP Appendix D.

of ignitions. For example, data has shown that the effectiveness of enhanced clearance diminishes during and after windy weather conditions. Additionally, the alteration of fuel loading along overhead conductors can provide additional risk-reduction benefits. Therefore, these may be considered as complementary risk control mechanisms.

2 Introduction

GO 95, Rule 35 mandates that "Where overhead conductors traverse trees and vegetation, safety and reliability of service demand that certain vegetation management activities be performed in order to establish necessary and reasonable clearances, the minimum clearances set forth in Table 1, Cases 13 and 14, measured between line conductors and vegetation under normal conditions shall be maintained." For conductors operating at 2,400 to 72,000 volts, GO 95, Rule 35, Appendix E recommends a minimum of 12 feet of clearance at time of pruning for facilities located in the HFTD and a minimum of 4 feet of clearance at time of trimming for facilities located outside of the HFTD.

The IOUs minimize vegetation contact risk through proactive vegetation management activities that catalog, audit, and prune or remove trees near electrical facilities. The terminology "enhanced clearance" has been misunderstood as a pruning practice that only takes the radial distance of vegetation from electric lines into consideration. In actuality, the three utilities follow a more balanced approach, considering what is necessary for safety, compliance, and reliability. In addition to the required minimum clearance, this balanced approach considers tree species, growth rate, site conditions, and tree health to determine the proper radial clearance for a tree. Additionally, industry pruning standards such as the American National Standards Institute (ANSI A300) guidelines factor into the determination of appropriate radial clearances.

This study focuses on quantifying the benefits of proactive pruning to 12 feet of clearance or greater at the time of pruning for primary distribution facilities. For the purposes of this study, clearances of 12 feet and above are defined as the "enhanced clearance". Factors other than clearance can also contribute to the likelihood of vegetation contact-caused outages ("outages"), such as inspection frequency. However, these factors are not captured quantitatively in the data set nor considered in this study.

2.1 Commonalities of Vegetation Management Practices Across Utilities

The IOUs' vegetation management practices may differ based on the unique aspects of their respective service territories. However, there are practices that are common across the IOUs. First, the IOUs generally perform tree inspections twice per year in the HFTD portions of their respective service territory and at least once per year within the non-HFTD. Second, the primary inspection method is foot patrol. Third, a clearance of 12 feet or greater at time of pruning is defined as the threshold when quantifying whether an IOU has obtained enhanced clearance. In addition, each utility uses professional judgement based on training and arboricultural knowledge to make case-by-case determinations of which trees are appropriate candidates to receive expanded clearances. That is, the determination of how much clearance is obtained at time of pruning is not made arbitrarily. The goal of establishing proper clearance is predicated on ensuring safety and compliance for at least the annual pruning cycle. Indeed, in some instances the health of a tree may be adversely affected by expanded clearances.

3 Data and Methods

3.1 Data Sample and Data Variables

Vegetation-caused outage data from the three IOUs were collected from year 2015 to 2022 based on the Quarterly Data Reporting (QDR) files. To accurately reflect annual outage frequency in comparison to the outage data filtered in the third-party's assessment, this time period was used to conduct the exploratory analysis. Additional asset data, such as primary distribution overhead circuit miles, were sourced from the Q1 2024 Quarterly Data Report[243].

A table of data variables is available in Appendix A: Definitions.

3.2 Exploratory Data Analysis

3.2.1 background for data interpretation:

Public Safety Power Shutoffs (PSPSs) are the proactive de-energization of power lines during severe weather to reduce the likelihood of power lines causing an ignition. During elevated or severe weather conditions warranting a PSPS event, especially Red Flag Warnings (RFW)[244], vegetation-caused outages are not recorded on de-energized circuits. Therefore, weather conditions associated with vegetation outages used in this study (also reported as "risk-events" in the Wildfire Mitigation Plan (WMP) QDR) do not include this type of dry windy conditions. This indicates that the conclusions on the effectiveness of the enhanced clearance drawn from this analysis are not relevant to weather conditions that meet PSPS protocol.

Unless otherwise specified, outages mentioned in this white paper refer to vegetation-caused outages.

3.2.2 Comparison of Overhead Circuit Miles and Land Cover across Utility Service Territories

A comparison of the land cover[245] across California is informative when evaluating the effectiveness of vegetation-related mitigation methods and developing a utility-specific strategy.

California's land cover is highly diverse, reflecting its varied geography. Northern California features dense forests, fertile valleys like the Central Valley, and mountainous areas like the Sierra Nevada range. This region receives more rainfall, contributing to its lush

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[243] The % of total primary distribution overhead circuit miles that were added or removed is relatively small. To simplify the calculation, the circuit miles data from 2024 Q1 QDR in a utility company are used for all the years.

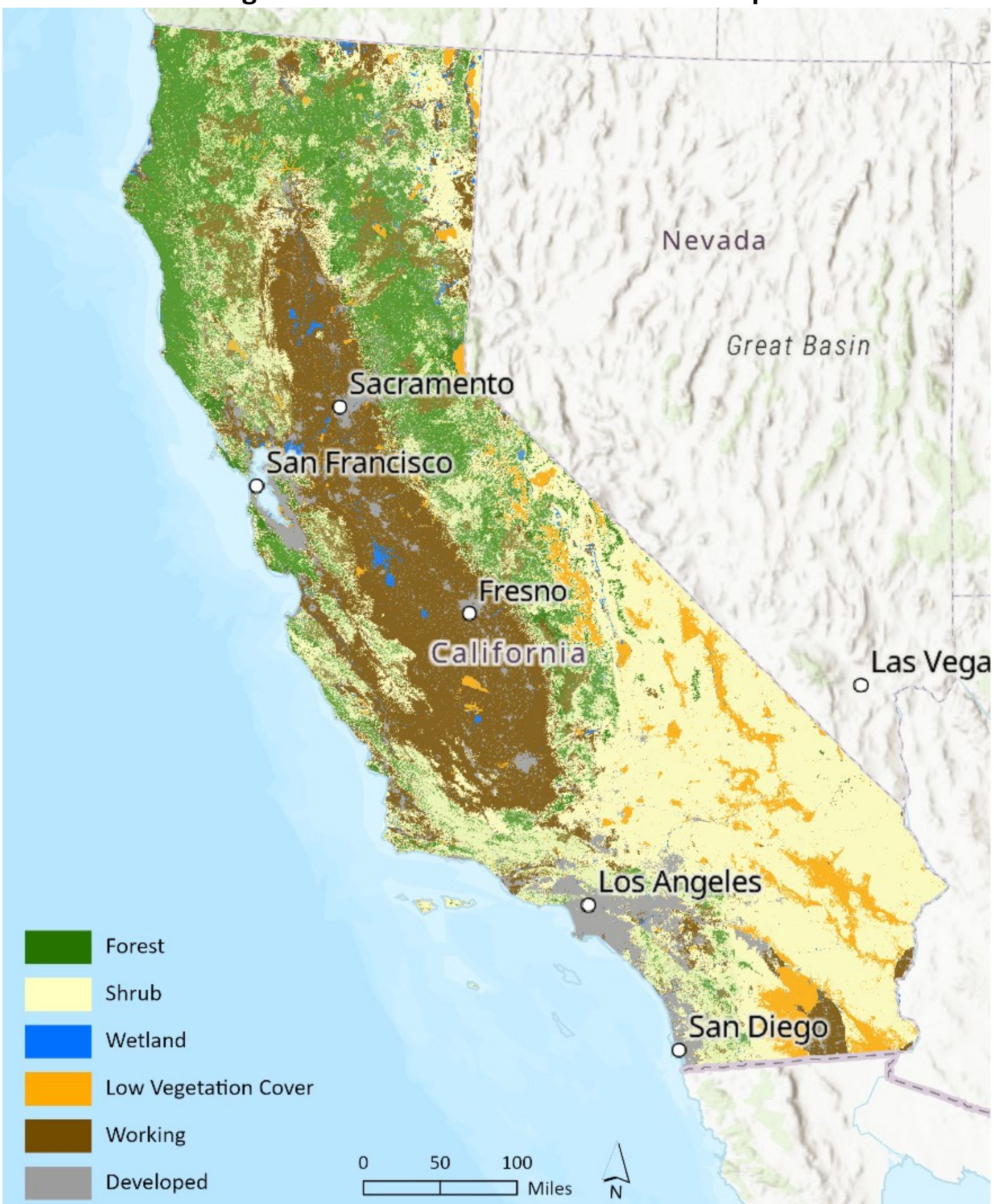
[244] RFW stands for Red Flag Warning issued by National Weather Service to alert areas of critical fire weather conditions, such as strong winds and low humidity, which could lead to extreme fire behavior.

[245] In the context of the National Land Cover Database (NLCD), land cover refers to the physical material at the surface of the earth. The NLCD provides detailed land cover data at a 30-meter spatial resolution, which is used for various environmental, land management, and modeling applications.

vegetation. In contrast, Southern California is characterized by arid deserts, coastal plains, and extensive urban development. The landscape here includes chaparral, coastal sage scrub, and palm trees, with a generally warmer and drier climate. These differences create distinct ecological zones and contribute to the unique identities of Northern and Southern California.

Figure 1 presents a land cover classification map of California, derived from the 2023 National Land Cover Database (NLCD). The map's land cover groups are categorized into stratified class bins based on the Anderson Level II Land Cover Classification System (Anderson, 1976).

Figure 1: California NLCD Land Cover map



Source: NLCD 2023 version. The grouping of the land cover types is included in Appendix A.

Table 1: Overheard Circuit Miles and Vegetation Outage Statistics by Land Cover

Utility Name and Sample Size	Metrics	Developed	Forest	Shrub	Wetland	Working	Low Veg Cover
PG&E HFTD miles = 25,293 non-HFTD miles = 54,485 HFTD outages = 16,245 non-HFTD outages = 13,183	Circuit miles % (HFTD)	42.0%	23.3%	18.6%	0.7%	15.2%	0.2%
	Circuit miles % (non-HFTD)	60.4%	0.5%	1.2%	0.8%	36.8%	0.3%
	Outages % (HFTD)	37.7%	49.0%	6.5%	0.6%	3.5%	0.3%
	Outage % in Non-HFTD	71.0%	10.4%	3.0%	1.1%	12.8%	0.3%
	Outages per mile (HFTD)	0.58	1.35	0.23	0.54	0.15	1.12
	Outages per mile (non-HFTD)	0.28	4.89	0.62	0.35	0.08	0.27
SCE HFTD miles = 13,743 non-HFTD miles = 36,787 HFTD outages = 987 non-HFTD outages = 2,354	Circuit miles % (HFTD)	46.4%	3.4%	34.5%	0.9%	14.6%	0.1%
	Circuit miles % (non-HFTD)	71.9%	0.02%	17.9%	0.2%	8.4%	1.6%
	Outages % (HFTD)	73.8%	12.7%	9.6%	0.5%	3.3%	0.1%
	Outage % in Non-HFTD	96.1%	0.1%	0.6%	0.0%	2.6%	0.6%
	Outages per mile (HFTD)	0.11	0.27	0.02	0.04	0.02	0.05
	Outages per mile	0.09	0.23	0.002	0	0.02	0.02

Utility Name and Sample Size	Metrics	Developed	Forest	Shrub	Wetland	Working	Low Veg Cover
	(non-HFTD)						
SDG&E HFTD miles = 3,378 non-HFTD miles = 2,950 HFTD outages = 134 non-HFTD outages = 341	Circuit miles % (HFTD)	39.6%	2.1%	47.6%	1.8%	8.8%	0.1%
	Circuit miles % (non-HFTD)	94.9%	0.05%	3.9%	0.3%	0.7%	0.2%
	Outages % (HFTD)	67.9%	4.5%	22.4%	3.7%	1.5%	n/a
	Outage % in Non-HFTD	99.7%	0.3%	0.0%	0.0%	0.0%	0.0%
	Outages per mile (HFTD)	0.07	0.08	0.02	0.08	0.01	n/a
	Outages per mile (non-HFTD)	0.12	0.72	0	0	0	0

* Outage data was collected from 2015 to 2022. A small portion of PG&E outage records (2.31%) are not spatially recorded; therefore, this table is a subset of all outages reported in the QDR.

As shown in Table 1, PG&E has the highest proportion of service territory classified as "Forest" among the three utilities, with 23 percent of its overhead primary circuits (5,905 miles) located in forested areas. Consequently, nearly 50 percent of vegetation-caused outages in the HFTD portion of PG&E's service territory are associated with forests, which also have the highest outage rate per mile. In comparison, SCE and SDG&E have 3.4 percent and 2.1 percent of their service territories classified as "Forest", respectively. Despite these differences, forests exhibit the highest outage rate among all three IOUs. The ratio of forest outage percentage in HFTD to forest circuit miles percentage in HFTD is greater than 2 to 1 for all IOUs, indicating that outages are proportionally more likely to occur in forested areas.

SDG&E has the smallest service territory of the three utilities. In the HFTD portion of SDG&E's service territory, the largest land cover type is "Shrub," accounting for 47.6 percent, followed by "Developed," accounting for 39.6 percent. However, nearly 68 percent of vegetation-caused outages occur in developed regions, while 22.4 percent occur in shrub land areas. Similar patterns are observed for SCE's HFTD territory, where

“Developed” and “Shrub” land cover account for 46.4 percent and 34.5 percent of the circuit miles in HFTD respectively. These land covers are responsible for 73.8% and 9.6% of the outages in the HFTD."

Fuel types associated with forest and shrub land cover in California are generally easier to burn compared to developed and other land cover types. Forests and shrublands contain a significant amount of vegetation, including grasses, shrubs, and trees, which can serve as fuel for wildfires. These areas often have a high density of fine fuels, such as leaves, needles, and small branches, which can ignite easily and burn rapidly. Therefore, the ignition risks associated with “Forest” and “Shrub” are generally higher than with other land cover. From a vegetation management perspective, shrub lands are generally easier to manage than forests. Shrub lands typically have less biomass and a simpler structure compared to forests, making them more accessible for management activities such as controlled burns, mechanical removal, and herbicide application. Additionally, shrubs often grow in more open areas, which can facilitate easier access for equipment and personnel.

Forests, on the other hand, have a more complex structure with multiple layers of vegetation, including understory, midstory, and canopy layers. In addition to vegetation structure, forests are subject to stringent permitting requirements guiding vegetation management activities. This complexity can make management activities more challenging and labor-intensive. Forest management often requires more specialized techniques and equipment to address issues like tree thinning, invasive species control, and maintaining biodiversity. The forests in PG&E’s service territory are challenging to manage, which contributes to the high outage rate discussed in Section 3.2.3.

“Forest” and “Shrub” lands combined in HFTD account for 41.9 percent of PG&E’s primary overhead circuit miles, 49.7 percent of SDG&E’s circuit miles, and 37.9 percent of SCE’s circuit miles. Outage rate per circuit mile across three IOUs are not comparable given the variation in land cover, however, outage rate per circuit mile between HFTD and non-HFTD within one IOU offers insights on the outcome of vegetation management activities. The outage rate per circuit mile within the HFTD forest land cover is significantly lower than in non-HFTD areas in PG&E’s territory. For instance, PG&E's outage rate is 1.35 outages per circuit mile in the HFTD compared to 4.89 outages per circuit mile in the non-HFTD. A similar pattern is observed in shrubland. This lower outage rate highlights the results of PGE’s comprehensive mitigation effort in the HFTD, partially attributed to enhanced clearances. SCE and SDG&E have a relatively small percentage of overhead circuit miles in the non-HFTD forest areas, therefore a similar comparison between HFTD and non-HFTD is not meaningful in this case.

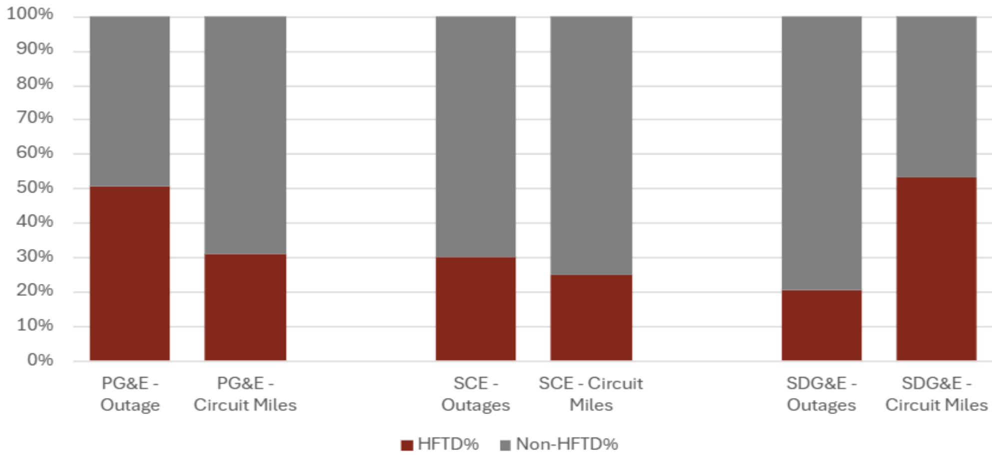
In conclusion, understanding the land cover types and their associated outage frequency and rate identifies factors beyond the radial clearance that impact the likelihood of vegetation-caused outages. This information can also guide utilities in researching and evaluating the minimum clearances based on land cover and in strategizing best practices.

3.2.3 Statistics on vegetation caused outages and ignitions

Outage Statistics Outside of RFW and HWW[246] Conditions

Figure 2 and Table 2 compare vegetation-caused outages in HFTD and non-HFTD portions of the service territories of each utility excluding RFW or HWW days. The comparison is shown by outage as well as by circuit miles.

Figure 2: Comparison of Vegetation Caused Outages Excluding RFW or HWW Days



Source: 2015-2022 WMP QDR

Table 2: Comparison of Vegetation Caused Outages Excluding RFW or HWW Days

Outages Outside of RFW or HWW Days	PG&E (n=39,851)	SCE (n=2,737)	SDG&E (n=276)
Annual actual frequency range (territory)	3,210 - 7,292	218 - 508	21 - 48
Percent of avg. outages in the HFTD	51%	30%	21%
Percent of circuit miles in the HFTD	31%	25%	53%
Range of annual percentage against all vegetation-related outages in HFTD	85.6% to 99.1%	65.3% to 91.3%	41.7% to 100%
Range of annualized frequency per 1000 miles in the HFTD**	51.1 - 174.0	6.6 - 17.8	0.9 - 4.5
Mean of annualized frequency per 1000 miles in HFTD*	101.0	10.8	2.1
Mean of annualized frequency per 1000 miles in non-HFTD*	45.0	8.4	7.5

Source: 2015-2022 WMP QDR Table 2 and Table 7

[246] HWW stands for high wind warning condition issued by the National Weather Service. A High Wind Warning is issued when sustained winds of 40 mph or higher are expected for at least an hour, or wind gusts of 58 mph or more are anticipated. "HWW" used in this paper are HWW conditions associated with winter storms and precipitation, without overlapped RFW conditions.

* Weather conditions vary greatly in each year; therefore the goal is to assess the outcome when such conditions do occur. Therefore, years when observations were 0 are not included when the mean is calculated.
** Circuit miles in HFTD are based on metrics in the Q1 2024 QDR.

Over half (53 percent) of the primary overhead circuit miles in SDG&E's service territory are in the HFTD versus 31 percent in PG&E's service territory and 25 percent in SCE's service territory. This demonstrates the unique terrain of each utility's service territory.

When comparing the proportion of outages that occur outside of RFW or HWW days to the proportion of overhead circuit miles in the HFTD, the data shows utilities have distinctive results. For PG&E, outages in the HFTD are proportionally higher than the circuit miles percentage. SCE's percentage of outages in the HFTD is very close to its circuit miles proportion. SDG&E's percentage of outages in the HFTD is much less than the proportion of overhead circuit miles in the HFTD.

The percentage of forest land in the HFTD can be used to indicate the density of vegetation along overhead circuits. As shown in Table 1, the outage rate among land cover types varies significantly. PGE's higher annualized outage frequency in HFTD could be partially explained by much higher percentage of forest in the HFTD compared to other utilities.

In contrast, SDG&E's outage proportion in the HFTD is much lower than the circuit mile proportion, and annualized outage frequency is more than three times (2.1/7.5) lower in the HFTD compared to the non-HFTD. However, this observation is associated with very low forest land cover (2.14 percent, 76 miles). SCE has a similar outage rate in both the HFTD and the non-HFTD, which might be due to the smaller percentage of its territory in the HFTD.

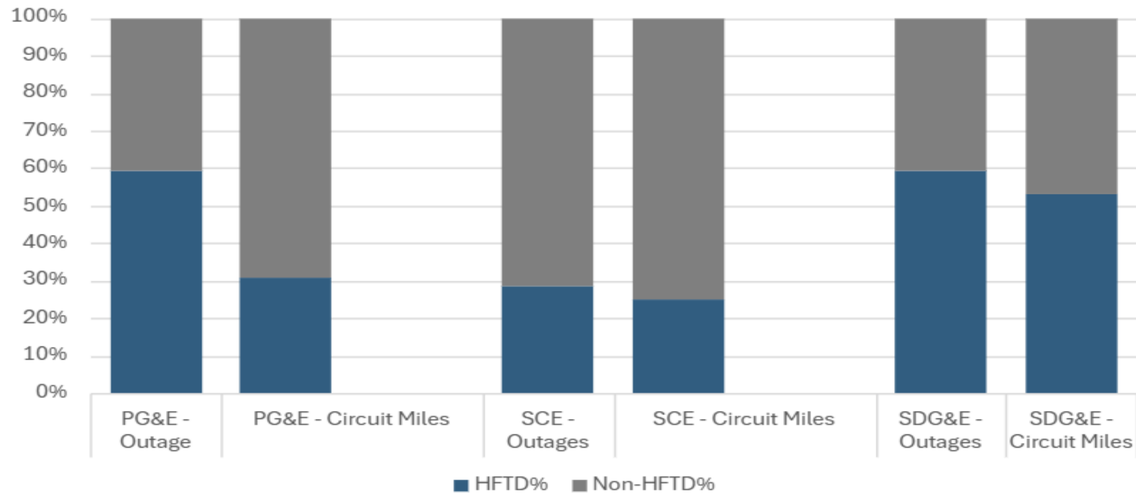
The effectiveness of enhanced clearances should be measured independently during wind events and non-wind events. The Annual Actual Outage Frequency range in Table 2 indicates that most vegetation contacts occurred outside of RFW and HWW conditions. While overall outage rates are higher in the HFTD compared to the non-HFTD for PG&E and SCE, Table 1 shows that the primary driver is likely due to the higher outage frequency in forest and shrubland compared to other land types. However, enhanced radial clearances in PG&E's HFTD forestland are associated with lower outage rates when compared to non-HFTD forestland. PG&E's outage rate in the forestland overall is still much higher than the rate in other land types. Therefore, further research is needed to determine the effective radial clearances required to reduce outage rates in forest and shrub regions to levels comparable to other land types.

Outage Statistics during RFW Conditions that don't trigger PSPS protocols

The impact of RFW and HWW weather conditions varies from event to event and across each service territory, and the pattern of these weather conditions is largely unpredictable. Understanding the influence of these weather conditions on vegetation-caused outages is crucial for evaluating the diminishing effectiveness of enhanced clearances. This also justifies the need for additional mitigation methods beyond enhanced clearances, thereby informing comprehensive mitigation strategies.

A small percentage of outages are observed during RFW weather conditions. The included RFW days do not meet the criteria to initiate PSPS protocols, possibly due to the moisture content of the fuel. RFW conditions vary from event to event, making comparison impossible due to spatial and temporal variations in weather factors. However, to compare outcomes across the utilities' service territories, overhead circuit mile days as a standardization method is used to generate the outage rate per 1,000 overhead circuit mile (OCM) days[247]. Additionally, the data sample used in this analysis does not include the RFW conditions that warrant PSPS protocols.

Figure 3: Comparison of Vegetation Caused Outages During RFW Conditions that do not Trigger PSPS Protocols



Source: 2015-2022 WMP Quarterly Data Report (QDR) Table 2 and Table 7

Table 3: Comparison of Vegetation Caused Outages during RFW Conditions that do not Trigger PSPS Protocols

Outages During RFW Days	PG&E (n=1,167)	SCE (n=381)	SDG&E (n=23)
Annual actual frequency range (territory)	2 - 297	0 - 117	0 - 12
Avg. outages % in HFTD*	59%	28%	59%
Circuit miles % in HFTD	31%	25%	53%
Range of annual percentage against all vegetation-related outages in HFTD	0.04% - 6.24%	0% - 26%	0% - 58.3%
Range of outage rate per 1000 OCM days (territory)	0.01 - 0.52	0 - 0.39	0 - 0.1
Mean of outage rate per 1000 OCM days (territory) **	0.27	0.22	0.05

Source: 2015-2022 WMP Quarterly Data Report (QDR)

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247 Overhead Circuit Mile (OCM) days is a metric collected in QDR Table 4. It measures the exposure of the overhead asset to a certain weather condition by using the product of time duration and circuit mile length. This can be used to understand some of the weather factors and general differences between each event or year.

* SCE’s vegetation management mitigation scope also includes State Responsibility Area (SRA) in addition to HFTD. SRA is not used in the white paper. The statistical impact is negligible.
** Weather conditions vary greatly in each year, the goal is to assess the outcome when such conditions do occur. Therefore, years when observations were 0 are not included when the average is calculated. The outage rate is annualized

Figure 3 indicates that the proportion of outages during RFW conditions closely matches the proportion of circuit miles in the HFTD. This impact is particularly evident in SDG&E's service territory, where the percentage of outage events in the HFTD during this type of RFW condition reaches 59 percent, a significant increase from 21 percent during no windy weather conditions. PG&E has a small increase, from 51 to 59 percent; whereas outages percentage in the HFTD portion of SCE‘s service territory does not have a significant difference.

This difference highlights the vulnerability to windy conditions and the reduced effectiveness of enhanced vegetation pruning in the HFTD. The differences of the outage rate per 1,000 OCM days are smaller across the three utilities during such RFW conditions when compared to the outage rate outside of RFW or HWW conditions. SDG&E‘s sample size is relatively smaller, making it less comparable to the other two utilities.

Outage Statistics during HWW Only Conditions

The impact is even more pronounced during HWW conditions, as shown in Table 4. Although these wet, windy conditions differ significantly from dry, windy conditions like Santa Ana winds, HWW conditions can still serve as a stress test to evaluate the effectiveness of greater clearance during strong winds. Since wet, windy conditions do not pose an elevated wildfire risk, utilities typically do not need to de-energize the lines as they do during conditions that present a higher fire risk, such as RFW. Therefore, outage observations are available for comparison.

Table 4 presents statistics for observations during HWW conditions. PG&E experienced up to 54.49 outages per 1,000 OCM days annually during HWW conditions. To demonstrate the wind impact on vegetation-caused outages, the outage rate outside of RFW and HWW was standardized using OCM days and then compared to the rate during HWW. Since PG&E has a larger outage data sample size, its mean annualized outage rate of 45.0 from Table 2 was used as an example to extrapolate the outage rate per OCM days. Assuming 45.0 outages per 1,000 miles occurred in the non-HFTD for 365 days, this rate is normalized as follows:

$$
\begin{aligned}
x(\text{OCM days}) &= \frac{\text{number of outages}}{\text{OCM} \times 365 \text{ days}} \times 1000 \\
&= \frac{\text{number of outages}}{\text{OCM}} \times 1000 \times \frac{1}{365} \\
&= \text{number of outages per 1000 miles} \times \frac{1}{365} \\
&= 45 \times \frac{1}{365} \\
&= 0.12 \text{ per 1,000 OCM days per year}
\end{aligned}
$$

After the above conversion, 45.0 outages per 1,000 miles per year would be equivalent to 0.12 per 1,000 OCM days on average per year, whereas the outage rate during HWW condition is 54.49 per 1,000 OCM days per year in PG&E's service territory. This large difference highlights the magnitude of the weather impact.

This type of windy condition can also contribute to a significant portion of outages, as evidenced by the 51.7 percent recorded in 2022 for SDG&E's service territory. This indicates the reduced effectiveness of enhanced clearance, similar to RFW conditions. Additional findings regarding HWW are explained in Section 3.2.3.2.

Table 4: Comparison of Vegetation Caused Outages Observed during HWW conditions that do not Trigger PSPS Protocols

Outages Within Only HWW Days	**PG&E (n=2,019)**	**SCE (n=265)**	**SDG&E (n=66)**
Annual actual frequency range (territory)	3 to 647	6 to 97	0 to 35
Avg. outages % in HFTD	61%	31%	24%
Circuit miles % in HFTD	31%	25%	53%
Range of annual percentage against all vegetation-related outages in HFTD	0% to 12%	3% to 19%	0% to 51.7%
Range of outage rate per 1000 OCM days (territory)**	0.62 to 54.49	0.05 to 0.67	0 to 0.9
Mean of outage rate per 1000 OCM days (territory) *	11.1	0.3	0.3

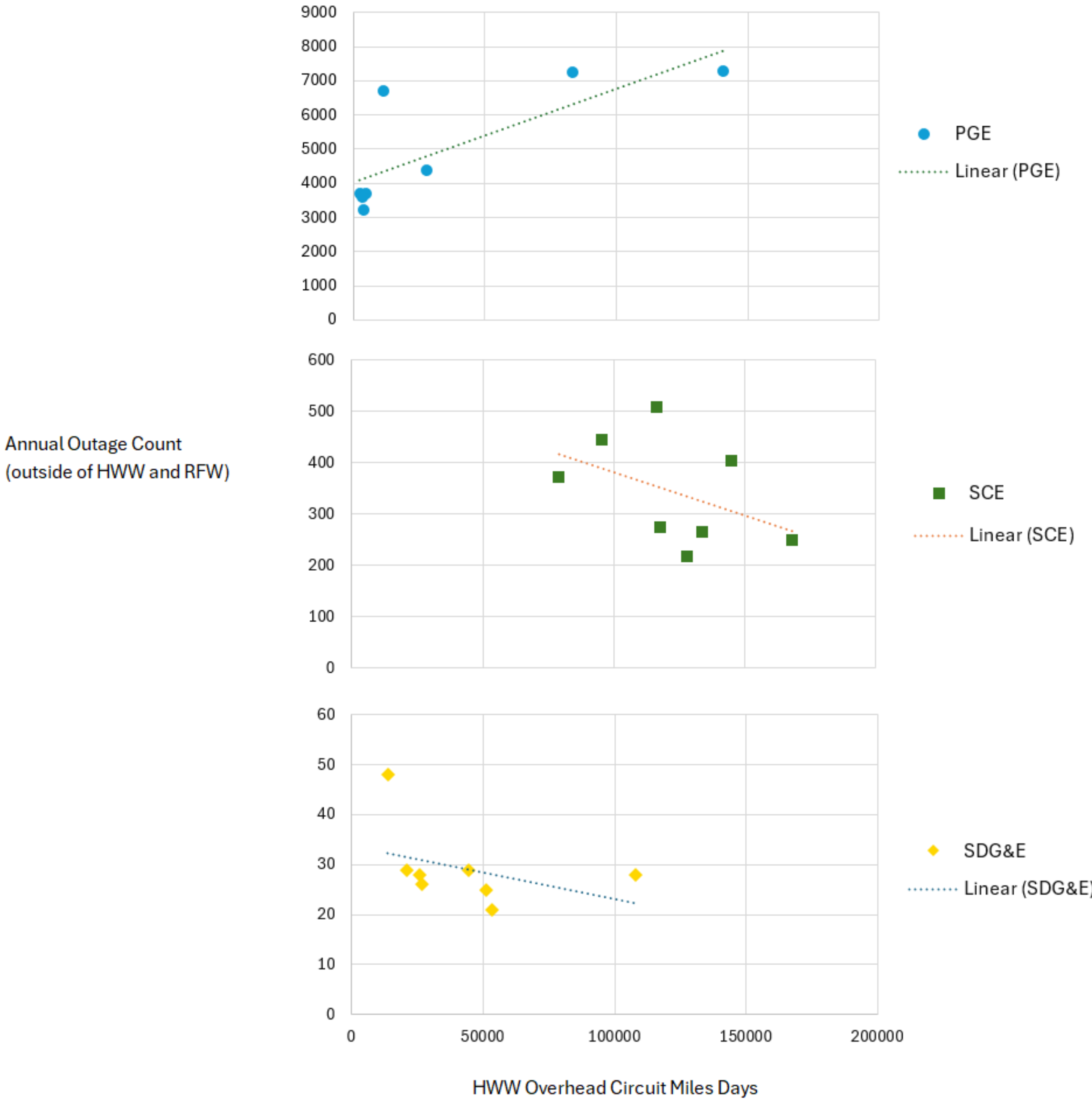
Source: 2015-2022 WMP QDR

* Weather conditions vary greatly in each year; the goal is to assess the outcome when such conditions do occur. Therefore, years when observations were 0 are not included when the average is calculated. The outage rate is annualized.

** OCM days is Overhead Circuit Mile days metric.

The impact of HWW Weather Condition on the Outage Frequency

Figure 4: Correlation between Outage Count Excluding HWW and RFW Conditions and Annual HWW Overhead Circuit Mile Days[248]



	PG&E	SCE	SDG&E
Pearson Correlation Coefficient	0.78	-0.45	-0.40

Source: QDR Table 2 and Table 4QDR

[248] HWW circuit mile days include some events that overlap with RFW conditions.

HWW conditions in Northern California are often associated with winter storms and atmospheric river events. These conditions typically occur during the winter months and bring strong winds, heavy rain, and sometimes snow to the region. In Southern California, HWW conditions are also common during winter storms.

As most HWW conditions bring rain to California during the winter season, they influence the annual outage frequency, not only during the HWW days but also for the rest of the year. However, this impact varies significantly between Northern and Southern California. Figure 4 provides a compelling observation that a strong positive correlation (0.78) is evident for the year when PG&E's service territory experienced a higher frequency of HWW conditions. In contrast, moderate negative correlations (-0.45 and -0.4) were observed for the years when SCE's and SDG&E's service territories experienced more HWW conditions. These observations may be attributed to the differences in vegetation type between Northern and Southern California. For Northern California, the data indicates that during years when greater HWW winter storms occur, higher outage frequency was observed. This insight can inform utility strategies for effective vegetation management practices, particularly in regions where outages are more likely to occur following HWW days. Additionally, this correlation between HWW and outage frequency also highlights the cause of the variation in the effectiveness of enhanced clearances year over year.

Vegetation Caused Ignition Frequency and Ignition per Outage

Ignition probability is directly influenced by factors such as fuel type, fuel moisture, wind, and heat sources. A heat source is derived from sparks generated when vegetation contacts bare conductors or when a tree strikes a covered conductor with enough force to break parts of the joints and other electrical devices. This can happen at a location with dry fuels or a location without any fuels. Therefore, not every vegetation contact (outage) has the same probability of causing an ignition.

Radial clearance as a treatment can reduce the probability of vegetation contact (outages) to a certain degree, as shown in Section 3.2.3 and Section 3.4. However, radial clearance on vegetation does not directly impact the probability of ignition. Statistically, assuming that ignition can happen randomly, reducing the probability of vegetation contacts through greater clearance logically leads to a reduction in the probability of vegetation contacts that result in ignitions.

The statistical relationship between clearance and ignition is that radial clearance can reduce the probability of vegetation contact with conductors, thereby reducing the overall number of outages. Radial clearance does not directly impact the probability of ignition once a contact occurs. The reduction in vegetation contacts indirectly reduces the number of potential ignition events.

Given that environmental factors vary greatly among utilities, ignitions per outage rate are not comparable among these regions. However, the differences between non-HFTD and HFTD areas within the same utility's service territory can offer some insights.

Table 5 shows that the average ignition frequency per 1,000 miles is higher in the HFTD than in the non-HFTD across all utilities, however, SDG&E has the smallest difference. Similarly, the ignition rate per outage in HFTD regions are higher than in non-HFTD regions, however, PG&E has the smallest difference.

Using SCE's rate as an example, the mean value in the HFTD is 0.0512, compared to 0.0321 in the non-HFTD. This means that on average, 100 outages would likely lead to 5 ignitions in the HFTD and 3 ignitions in the non-HFTD. In SDG&E's territory, the ignition rate is 2.8 times higher in the HFTD, but the outage rate in the HFTD is one third of the rate in the non-HFTD (see Table 2).

The higher rate in the HFTD might be attributed to more rural regions, such as the Wildland-Urban Interface (WUI), where fuel conditions are more prone to fire. This also indicates that enhanced clearance as a mitigation treatment alone is less likely to reduce ignitions if fuel conditions around the overhead assets remain unchanged.

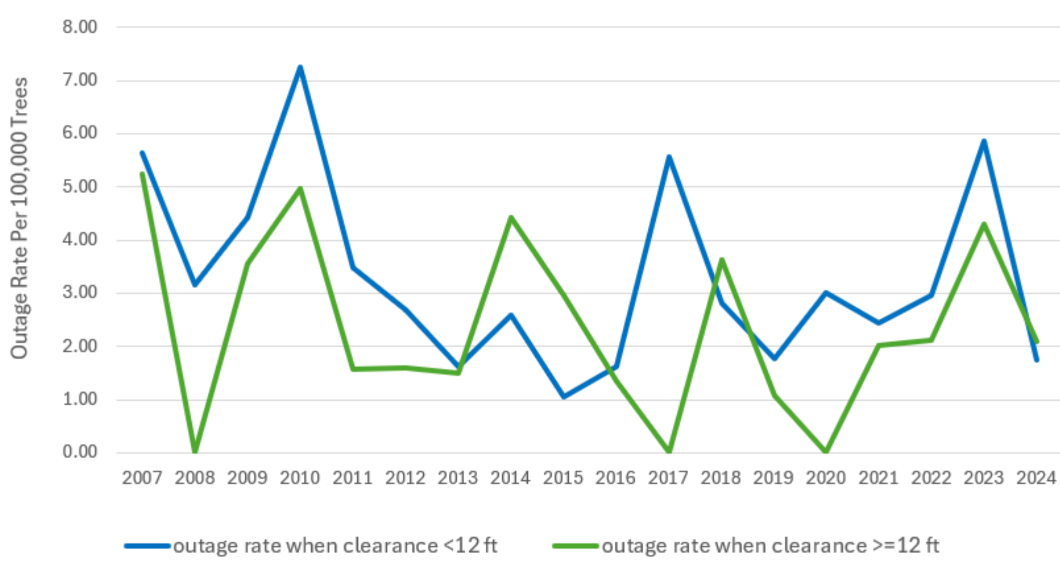
Table 5: Vegetation Caused Reportable Ignitions and Statistics (Annualized)

Mean ± Standard Deviation (μ±σ)	PG&E (n=1025)	SCE (n=114)	SDG&E (n=18)
Ignition per 1000 miles – HFTD	2.678 ± 0.658	0.570 ± 0.187	0.654 ± 0.501
Ignition per 1000 miles – non-HFTD	1.122 ± 0.234	0.313 ± 0.066	0.593 ± 0.382
Ignition rate per outage – HFTD	0.027 ± 0.013	0.051 ± 0.032	0.229 ± 0.206
Ignition rate per outage – non-HFTD	0.026 ± 0.008	0.032 ± 0.011	0.059 ± 0.045

Source: 2015-2022 WMP QDR

Outage Rate Comparison by Clearance Range

Figure 5: Outage Rate per 100,000 Trees in the HFTD Portion of SDG&E's Service Territory from 2007 to 2024



	<12 ft	>=12 ft
average percentage of all trees inspected in HFTD (2007-2017)	73.3%	26.7%
average percentage of all trees inspected in HFTD (2018-2024)	64.6%	35.4%
outage sample	102	31
average outage rate (2007-2024)	3.3	2.4

Note: To evaluate the effectiveness of clearance, outages captured in this data sample only include trees that have been inspected and maintained prior to the outage events. The outage sample size is 133.

To effectively quantify the outage rate for trees that are either maintained[249] or pruned to an enhanced clearance, data collection must include the radial clearance at the time of inspection and pruning, as well as the estimated clearance when outages occurred. SDG&E has been collecting such data for over two decades; therefore, outage data were sampled from SDG&E's service territory to conduct this analysis.
As observed in Figure 5, in 16 out of the 18 years the outage rate for trees with enhanced clearances (>=12 ft) was lower than the trees with less clearances. This finding indicates that when vegetation clearance is maintained or pruned to enhanced clearances, it reduces the outage frequency by 27 percent on average (difference between 3.3 and 2.4).

3.3 Statistical analysis on the effectiveness of vegetation clearance

3.3.1 Method and MachiNe Learning Model Selection for Statistical Inference

The purpose of statistical inference and logistic regression

The goal of this analysis is to quantify the probability of a vegetation caused outage event that could happen given the input variables, such as species or clearance and specifically how one input variable, clearance, impacts the probability of vegetation outages when holding other input variables consistent.
Logistic regression models the probability that a given input belongs to a particular class. It uses the logistic function (also known as the sigmoid function) to map predicted values to probabilities between 0 and 1. One of the strengths of logistic regression is its interpretability. The coefficients (weights) can be interpreted as the log odds of the outcome, making it easier to understand the influence of each feature (input variables). Therefore, logistic regression was selected to quantify the influence of clearance on the probability of vegetation outages. Additionally, to understand the level of impact that clearance has on the probability of outages, a sensitivity analysis is used to answer the

[249] SDG&E tracks and records the radial clearance on every inventory tree at the time of routine inspections. When a tree does not require pruning in the annual inspection cycle, it means its radial clearance is maintained at a targeted sufficient distance. When a tree does require pruning after inspection, the radial clearance is pruned to a targeted sufficient distance for at least one annual cycle.

‘what if’ question, namely, "if no trees were maintained with enhanced clearance, how many vegetation outages would have occurred?”.

A modified version of the test dataset was created by adjusting records with clearance values greater than 12 feet to have values of 11 feet. This modified test dataset was then used to generate new probabilities of vegetation related outages. Differences were then compared between the probability of outage based on the actual clearance and the probability of outage when enhanced clearances (values greater than 12 feet) are modified to 11 feet.

Data samples and data frame used for modeling

The data sample used for this statistical inference consisted of records captured throughout the SDG&E service territory. SDG&E is the first utility in California to track and record vegetation activities and tree-related variables at the tree level. This precise data collection enables advanced statistical inference by providing detailed information on tree features. Consequently, this data sample was selected for the analysis. Data recorded from 2006 to 2022 was used to train the logistic regression model, and data recorded from 2023 to 2024 was used to conduct the sensitivity analysis.

Data Variables

The response variable positive and negative observation were encoded for each Tree ID in each calendar year. If a Tree ID had an outage, then the output was classified as 1, otherwise, the output was classified as 0. Figure 6 shows the predictive variables that are important in this model. A logistic regression model was trained to predict the probability of a tree causing an outage. This step establishes a statistical algorithm using logistic regression, which can be used to conduct the sensitivity analysis.

Figure 6: Predictive Variables used in the Final Machine Learning model

	0	Coefs
0	species_grp_Ash	-0.986696
1	species_grp_Avocado	-1.058510
2	species_grp_Brush 5X5 Bamboo	-0.041978
3	species_grp_Century Plant	0.444559
4	species_grp_Cottonwood	-0.565706
5	species_grp_Eucalyptus	-0.123354
6	species_grp_Oak	-1.021837
7	species_grp_Other	-1.343835
8	species_grp_Palm-Date	-0.060114
9	species_grp_Palm-Fan	0.821419
10	species_grp_Palm-Feather	-0.426131
11	species_grp_Pepper (California)	-0.917737
12	species_grp_Pine	-0.111842
13	species_grp_Silk Oak	-0.174798
14	species_grp_Sycamore	-0.276343
15	species_grp_Willow	-0.932854
16	vma_grp_200	-0.663902
17	vma_grp_300	-1.894322
18	vma_grp_400	-1.443127
19	vma_grp_500	-0.608306
20	vma_grp_600	-1.319338
21	vma_grp_700	-0.846762
22	growthrate_FAST	-1.448301
23	growthrate_MED	-1.833513
24	growthrate_NR	-0.133987
25	growthrate_SLOW	-1.922541
26	growthrate_VFST	-1.437415
27	LINECLR_MID_scale	-2.277939
28	DBH_MID_scale	1.670327
29	TREEHEIGHT_MID_scale	3.663053
30	enhanced_clear_yes	-0.630047

3.3.2 Model Output and Interpretation

Table 6 presents the results from a model trained on data from 2006 to 2022 and tested on data from 2023 and 2024. Due to the significantly lower number of positive observations compared to negative ones, the model is imbalanced. However, the primary objective of this regression is to perform a sensitivity analysis, focusing on the predicted true positive outcomes.
More details on model performance can be found in Appendix B.

Table 6: Model Output with Actual Clearance Values (unit=outages in 2023 and 2024)

Confusion Matrix Using True Clearance Values		Actual		
		Outage	No Outage	Total
Predicted	Outage	47	162,971	163,018
	No Outage	15	610,267	610, 282
	Total	62	773,238	773,300

According to the model output shown in Table 6, 62 actual outages were observed from 2023 to 2024 and the model correctly predicted 47 out of 62. Based on the true positive and false positive ratio derived from this true test data, these ratios are then used to split the calculated true outages and calculated false outages in Table 7.

Table 7: Model Output after Altering Clearance Values (unit=outages in 2023 and 2024)

Confusion Matrix Using Altered Clearance Values		Calculated (used as actual)		
		Outage	**No Outage**	**Total From Model**
Predicted	Outage	62.8	217,955.2	218,018
	No Outage	13.9	555,237.1	555,251
	Total	76.7	773,192.3	773,300

The actual values for the variable "clearance" were adjusted to 11 if they exceed 11. After modifying the clearance values, the same algorithm was rerun to generate the performance output shown in Table 7. As a result, the calculated actual outage count increased from 62 to 76.7. The following formula illustrates the difference in outage counts between scenarios where some trees have enhanced clearances and where no trees have enhanced clearances. This method indicates that enhanced clearances reduced approximately 20% of vegetation-caused contacts.

$$(76.7 \times \textit{Sensitivity Analysis Outage Count}) - (62 \times \textit{Actual Outage Count}) \\ = \textit{Approximately } 15 \textit{ Potential Mitigated Outage}$$

3.3.3 Conclusion of the Statistical Inference

This sensitivity analysis provides further evidence that greater clearance reduces the probability of vegetation-caused outages, thereby resulting in fewer ignitions. This method helps quantify the impact by modifying one variable while holding other variables constant. However, it does not directly specify the clearance that should be adopted.

Limitation of the Statistical Inference

3.4.1 Data variables not included in the statistical inference.

The variation in the tree canopy is not considered in the model. Based on variables used in the third-party's analysis, the average of "Tree Canopy Cover" in PG&E's service territory is close to three times the average tree canopy cover in SCE's and SDG&E's service territories.

Additionally, variation in land cover is not captured in the regression model. The land cover identified at locations where outages are observed differs between Northern and Southern California.

Wind gust is not included as a variable. This model is not designed to make real-time predictions.

4 Comments on the Third-Party Memo Regarding the Effectiveness of Enhanced Clearance

4.1 Interpretation on the sample size of response variable “Time-to-Outage”

Time-to-Outage in the third-party analysis is defined as the days between the time when a tree received a pruning or inspection that recorded a clearance and the time when a tree caused an outage. This variable is used to measure the difference in duration among clearance categories to evaluate whether greater clearance is associated with longer duration.

Table 8 is interpreted as the sample size of the response variable “time-to-outage” collected from each utility and grouped by different radial clearance category. The sample size might not represent the ratio of the outage tree population for each clearance category. For PG&E, it should be noted that there is not a direct connection between the outage records and the vegetation management database (inspection/tree work records). The data used in Table 8 was derived by geo-referencing location of outage tree and vegetation management records and filtering results based on multiple factors described in the third-party report. Because of the high variability in factors that influence this data, no direct conclusions should be drawn from PG&E data in Table 8

Table 8: Response variable “Time-to-Outage” by clearance and its sample size

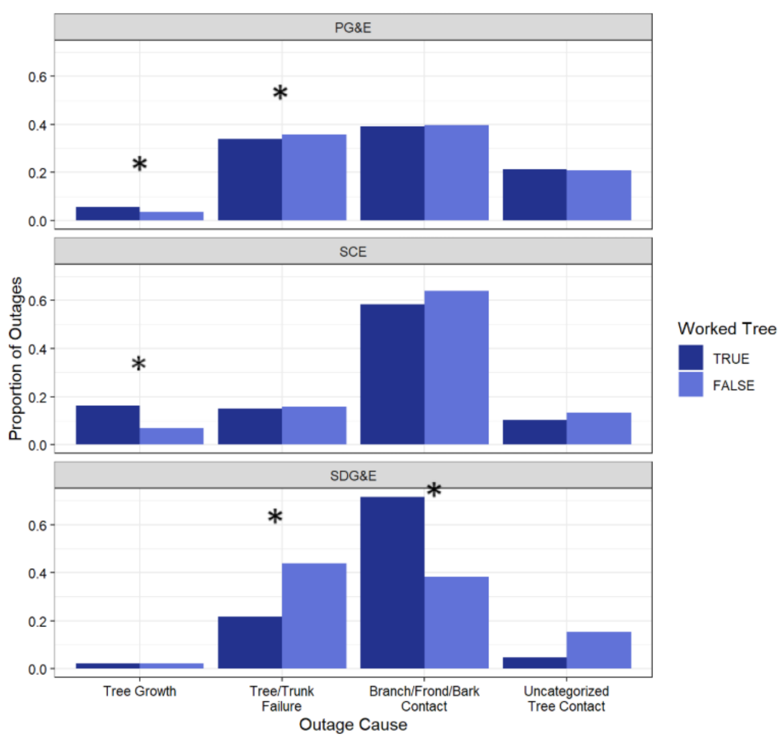
	“Time-to-Outage” Variable Sample Size (n=1,345)			Summary Stats			
Radial Clearance Category	**PG&E**	**SCE**	**SDG&E**	**Overall Mean (time-to-outage)**	**Median (time-to-outage)**	**Standard Error (time-to-outage)**	**Standard Deviation (time-to-outage)**
0-4 ft	8	13	6	287 days	121	85.5	444
4-12 ft	268	102	139	425 days	201	25.2	569
>12 ft	760	22	27	619 days	336	21.8	619

4.2 Interpretation and Comments on “Outage Variations Between Worked and Non-worked Trees”

The third-party analysis stated that “IOUs differed in the proportion of outages caused by worked trees. Approximately two-thirds of SDG&E outages in the analysis subset were caused by worked trees (67.7 percent), whereas PG&E had 25.1 percent of outages caused by work trees, and SCE only had 5.0 percent of outages caused by worked trees”. This

information indicates the proportion of trees that caused outages were previously recorded and maintained. The word "worked trees" is used to describe such observations.
However, the third-party analysis overlooks the differences in data collection practices across the three utilities when making related statements, meaning these percentages do not reflect the true ratio. For instance, PG&E does not record data when a tree is inspected but does not require follow-up, whereas SDG&E collects data on every tree at the time of its annual inspection, regardless of whether follow-up work is needed. This explains SDG&E's 67.7 percent figure. The correct interpretation of this number is that 67.7 percent of outages are caused by trees that have records and were inspected each year. This statement does not apply to PG&E, as not every tree inspection is recorded. Similarly, SCE did not historically collect data from every inspected tree, making the linkage between inspection activities and outages unclear. Therefore, no conclusions should be based on such data.
Additionally, this information has little relevance to the effectiveness of radial clearance. Based on data collected by SDG&E, when trees were not tracked and inspected prior to an outage event, their locations were much further from the conductors and thus not recorded. When evaluating the effectiveness of radial clearance, SDG&E excludes these tree records.
Work order data records are used to determine the date of previous inspection or tree pruning activities, allowing the duration between the previous clearance and the outage to be quantified. Figure 7 from third-party report is misleading given the flaws in data records.

Figure 7: EPRI assessment Figure 3-9

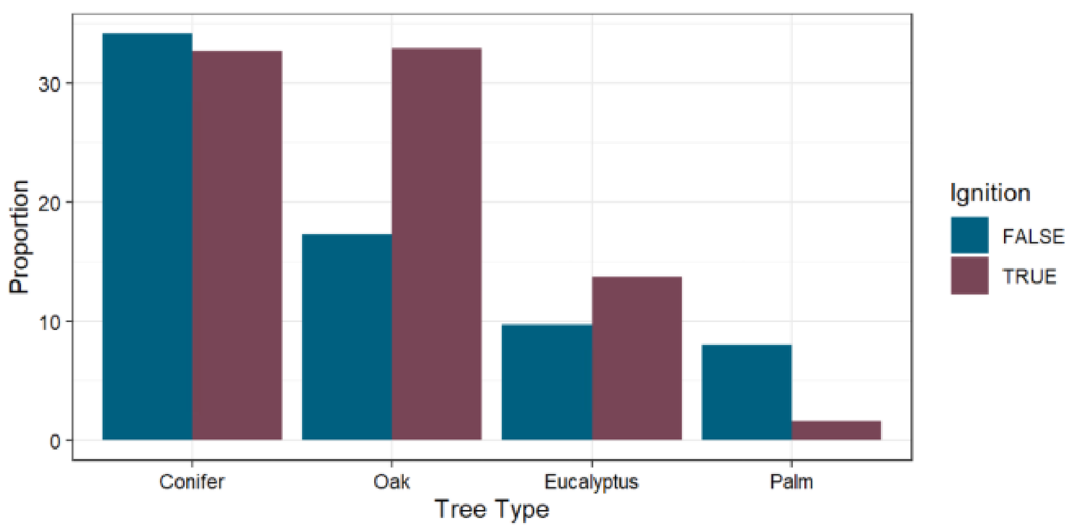


Source: Third-Party Report, Figure 3-9 The proportion of outages in each utility and outage cause based on work status (i.e., whether the tree was trimmed prior to an outage). When Worked Tree is TRUE, then the outage tree had been trimmed prior to causing an outage. Stars (*) indicate significant 2-sample proportion tests ($p < 0.05$) between worked-tree outages and non-worked-tree outages.

4.3 Ignition Species

The third-party analysis uses information in Figure 8 to suggest an association between tree species and ignitions. However, this graph is misleading as it may imply a direct causal relationship between species and ignition. The reality is that the likelihood of a tree species catching fire is not inherent to the species itself, but rather related to the type of fuels typically found in their vicinity. Therefore, it is the surrounding fuel types, not the tree species, that directly impact the probability of ignitions.

Figure 8: Variation in the Proportion of Outages without Ignitions and Outages Associated with Ignitions for the Top Genera Contributed to Outages.



Source: Third-Party Report, Figure 3-8 Variation in the proportion of outages without ignitions and outages associated with ignitions for the top genera contributing to outages. Conifers include Pinus spp., Sequoia spp., and Pseudotsuga spp. Oaks include Quercus spp. Eucalyptus includes Eucalyptus spp. Palms include Washingtonia spp. and unknown palms.

5 Conclusions and Recommendations based on Enhanced Clearance Study

As shown in this study, different methods have been used by the utilities and third parties to evaluate the effectiveness of enhanced clearance. Results demonstrate that greater clearance reduces the probability of outages by a measurable amount. A reduction in outage frequency can subsequently result in a lower incidence of ignitions in regions characterized by fire-prone vegetation.

However, the effectiveness of enhanced radial clearances alone in reducing the likelihood of ignitions is limited. Weather conditions can be a direct contributing factor to the probability of ignitions. For example, data has shown that the effectiveness of enhanced clearance diminishes during and after windy weather conditions. Additionally, the alteration of fuel loading under and adjacent to overhead conductors can provide additional risk-reduction benefits. Therefore, these may be considered as complementary risk control mechanisms.

Importantly, recognizing the differences between utility landscapes and land cover is crucial for effective risk management. As shown by the outage and ignition rates in this study, each utility has its own unique challenges related to risk due to differences in land cover. Utilities with significantly larger amounts of forested land face different and unique challenges compared to those with smaller service territories and less diverse land cover types. This study recommends utilities determine areas where historically higher wind gusts and drier fuel conditions may necessitate prioritization and frequency of inspection and tree pruning activities. Additional mitigation methods should be considered particularly in forest and shrubland areas. Such a strategy should consider location-specific treatments or enhanced clearance practices.

Establishing proper radial clearances at time of pruning is imperative to maintaining safety, compliance and reliability. The determination of proper clearance should take into account multiple factors including among others: species, growth rate, minimum clearance requirement, hazard abatement, line and tree movement, industry pruning standards, and tree health. There is a logical inference that increased clearances would result in reduced outages and, by association, ignitions. Indeed, recommendations set forth in General Order 95, Rule 35 state that radial clearances of 12 feet in the HFTD:

> *…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. Reasonable vegetation management practices may make it advantageous for the purposes of public safety or service reliability to obtain greater clearances than those listed below to ensure compliance until the next scheduled maintenance. Each utility may determine and apply additional appropriate clearances beyond clearances listed below, which take into consideration various factors, including: line operating voltage, length of span, line sag, planned maintenance cycles, location of vegetation within the span, species type, experience with particular species, vegetation growth rate and characteristics, vegetation management standards and best practices, local climate, elevation, fire risk, and vegetation trimming requirements that are applicable to State Responsibility Area lands pursuant to Public Resource Code Sections 4102 and 4293*.

The CPUC recommendation recognizes the establishment of enhanced clearances as a prudent method of preventing outages and ignitions that considers multiple and interrelated factors, and that this decision is made by professionals who understand and apply sound arboricultural practices. However, utility practices do not simply employ a radial clearance at time of pruning that is arbitrary or pre-determined. Rather, site-specific and tree-specific conditions should be considered to implement the most appropriate clearance to ensure compliance for the annual cycle.

This study also acknowledges the benefit of record keeping practices that connect tree related outage and ignition data to the work activity records to gain greater insight into clearance and trends in tree failure. By collecting higher frequency data over time utilities may identify patterns in vegetation growth and tree health. This will allow utilities to modify their clearance practices accordingly. Without sufficient data collection, opportunities for learning and improvement are reduced. It is recommended that each IOU make efforts to implement within their data records the ability to associate outage and ignition investigation information as part of their work activity history.

Finally, utilities, especially those with a large service territory, may benefit by leveraging remote sensing technologies such as LiDAR and satellite imagery to monitor clearance and tree health conditions. The evolution of vegetation management hinges on the development and effective use of data analytics, enabling a shift towards a more targeted and proactive vegetation mitigation strategy.

6 Discussion on Combined Mitigations and Implementations

The three IOUs' data sample, used in this study, does not holistically represent the effectiveness of combined mitigations. One of the main alternative mitigations is the use of covered conductor, which is used as an alternative to undergrounding and for the purpose of preventing ignitions caused by tree and power line contacts. Since covered conductor is a relatively recent engineering mitigation measure deployed by the IOUs, additional time will be required to further analyze its effectiveness combined with other mitigation measures.

Such mitigation strategies cannot be evaluated solely based on the cost-effectiveness of risk reduction. A key criterion is whether the combined mitigation can reduce the use of PSPS, enhance safety and reliability, and minimize impact to customers. Wildfires are one of the top risks facing Californians. However, a sustainable and reliable energy infrastructure is crucial for the future of electrification, social stability, economic growth, and long-term prosperity of the region.

The IOUs will explore further studies on alternative mitigations that involve enhanced tree pruning and associated lifecycle cost. The future implementation and milestones will depend on the effectiveness of this combined mitigation approach.

Appendix A: Supporting Data

Data Variables

Variable	Description
ANSI	American National Standards Institute
avg. ignition per 1000 miles	Total number of ignitions that occur over a given length of infrastructure and dividing it by the total miles of that infrastructure, multiplied by 1000.
avg. ignition rate per outage	Total number of ignitions divided by the total number of outages.
avg. outage rate per 1000 miles	Total number of outages that occur over a given length of infrastructure and dividing it by the total miles of that infrastructure, multiplied by 1000.
CPUC	California Public Utilities Commission
enhanced clearance	clearances of 12 feet and above
EPRI	Electric Power Research Institute
GO	General Order
HFTD	High Fire Threat District
HWW	high wind warning condition issued by the National Weather Service. A High Wind Warning is issued when sustained winds of 40 mph or higher are expected for at least an hour, or wind gusts of 58 mph or more are anticipated. "HWW" used in this paper are HWW conditions associated with winter storms and precipitation, without overlapped RFW conditions.
IOUs	investor-owned utilities: San Diego Gas & Electric Company (SDG&E), Pacific Gas and Electric Company (PG&E), and Southern California Edison Company (SCE)
land cover	In the context of the National Land Cover Database (NLCD), land cover refers to the physical material at the surface of the earth. The NLCD provides detailed land cover data at a 30-meter spatial resolution, which is used for various environmental, land management, and modeling applications.
NLCD	National Land Cover Database
Overhead Circuit Miles (OCM)	Overhead Circuit Mile (OCM) days is a metric collected in QDR Table 4. It measures the exposure of the overhead asset to a certain weather condition by using the product of time duration and circuit mile length. This can be used to understand some of the weather factors and general differences between each event or year.
PSPSs	Public Safety Power Shutoffs
QDR	Quarterly Data Reporting
RFW	Red Flag Warning issued by National Weather Service to alert areas of critical fire weather conditions, such as strong winds and low humidity, which could lead to extreme fire behavior.
SRA	State Responsibility Area
WUI	Wildland-Urban Interface

Supporting Data for Figure 1 and Table 1

Utility Name	Circuit Miles within the Service Territory	Developed	Forest	Shrub	Wetland	Working	Low Veg Cover	Unknown	Totals
PG&E	Circuit Miles (HFTD)	10,621	5,905	4,697	181	3,845	44		25,293
PG&E	Circuit Miles (non-HFTD)	32,911	279	649	411	20,069	166		54,485
Utility Name	**Outages (IOUs)**	**Developed**	**Forest**	**Shrub**	**Wetland**	**Working**	**Low Veg Cover**	**Unknown**	**Totals**
PG&E	Counts (HFTD)	6,128	7,968	1,064	97	563	49	376	16,245
PG&E	Counts (non-HFTD)	9,358	1,367	402	144	1,683	45	184	13,183
Utility Name	**Circuit Miles within the Service Territory**	**Developed**	**Forest**	**Shrub**	**Wetland**	**Working**	**Low Veg Cover**	**Unknown**	**Totals**
SCE	Circuit Miles (HFTD)	6,381	466	4,743	127	2,007	18		13,743
SCE	Circuit Miles (non-HFTD)	26,443	9	6,601	56	3,105	573		36,787
Utility Name	**Outages (IOUs)**	**Developed**	**Forest**	**Shrub**	**Wetland**	**Working**	**Low Veg Cover**	**Unknown**	**total**
SCE	Counts (HFTD)	728	125	95	5	33	1		987
SCE	Counts (non-HFTD)	2,262	2	14	0	62	14		2,354

Utility Name	Circuit Miles within the Service Territory	Developed	Forest	Shrub	Wetland	Working	Low Veg Cover	Unknown	Totals
SDG&E	Circuit Miles (HFTD)	1,338	72	1,607	61	296	3		3,378
SDG&E	Circuit Miles (non-HFTD)	2,799	1	115	9	22	5		2,950
Utility Name	**Outages (IOUs)**	**Developed**	**Forest**	**Shrub**	**Wetland**	**Working**	**Low Veg Cover**	**Unknown**	**Totals**
SDG&E	Counts (HFTD)	91	6	30	5	2	0		134
SDG&E	Counts (non-HFTD)	340	1	0	0	0	0		341

Supporting Data for Figure 2

Circuit Miles as of 2024Q1

SDG&E	HFTD	3,363
SDG&E	Non-HFTD	2,951
PG&E	HFTD	24,694
PG&E	Non-HFTD	55,243
SCE	HFTD	9,439
SCE	Non-HFTD	28,381

Distribution – No RFW or HWW

Outages	Tier	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	Sum
SDG&E	HFTD	7	15	11	5	6	4	6	3	0	0	57
SDG&E	Non-HFTD	18	33	17	16	20	24	23	68	51	0	219
PG&E	HFTD	2005	2310	3752	1714	4304	2134	2503	1263	2086		19985
PG&E	Non-HFTD	1695	2059	3540	1496	2954	1577	4221	2324	7548		19866
SCE	HFTD	85	153	127	84	168	66	74	63	112		820
SCE	Non-HFTD	287	355	277	182	276	152	201	187	0	240	1917

Distribution – No RFW or HWW

Outages	Tier	HFTD%	Non-HFTD%	Average	Annualized HFTD%	Annualized non-HFTD%
SDG&E	HFTD	0.21		7	0.21	
SDG&E	Non-HFTD		0.79	27		0.79
PG&E	HFTD	0.50		2498	0.50	
PG&E	Non-HFTD		0.50	2483		0.50
SCE	HFTD	0.30		103	0.30	
SCE	Non-HFTD		0.70	240		0.70

Supporting Data for Figure 3

Distribution – RFW Days

Outages	Tier	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	Sum
SDG&E	HFTD	0	0	4	7	0	1	0	0	0		12
SDG&E	Non-HFTD	0	0	3	5	2	1	0	0	0	0	11
PG&E	HFTD	4	1	118	51	21	142	64	4	2		405
PG&E	Non-HFTD	5	1	123	26	254	155	163	35	0	0	762
SCE	HFTD	0	5	50	19	9	16	9	0	2		108
SCE	Non-HFTD	0	14	67	92	35	41	24	0	3	0	273

Distribution – RFW Days

Outages	Tier	HFTD%	Non-HFTD%	Average if not 0	HFTD%	Non-HFTD%
SDG&E	HFTD	0.52		4	0.59	
SDG&E	Non-HFTD		0.48	3		0.41
PG&E	HFTD	0.35		51	0.35	
PG&E	Non-HFTD		0.65	95		0.65
SCE	HFTD	0.28		18	0.28	
SCE	Non-HFTD		0.72	46		0.72

Distribution – HWW Only Days

Outages	Tier	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	Sum
SDG&E	HFTD	1	2	7	0	0	1	1	4			16
SDG&E	Non-HFTD	1	11	28	2	0	0	7	1			50
PG&E	HFTD	22	37	402	1	341	0	358	7	0	167	1168
PG&E	Non-HFTD	13	23	245	2	291	3	267	7	0	106	851
SCE	HFTD	11	14	17	3	10	19	3	6			83
SCE	Non-HFTD	18	16	80	31	20	12	3	2			182

Distribution – HWW Only Days

Outages	Tier	HFTD%	Non-HFTD%	Average if not 0	HFTD%	Non-HFTD%
SDG&E	HFTD			3	0.24	
SDG&E	Non-HFTD			8		0.76
PG&E	HFTD	0.58		167	0.61	
PG&E	Non-HFTD		0.42	106		0.39
SCE	HFTD	0.31		10	0.31	
SCE	Non-HFTD		0.69	23		0.69

Supporting Data for Figure 4

Utility	Year	Outages – no HWW or RFW	Outages – HWW Only	HWW OCM Days
PG&E	2015	3700	35	2394
PG&E	2016	4369	60	28023
PG&E	2017	7292	647	140758
PG&E	2018	3210	3	3997
PG&E	2019	7258	632	83182
PG&E	2020	3711	3	4862
PG&E	2021	6724	625	11470
PG&E	2022	3587	14	3235
SCE	2015	372	29	78965
SCE	2016	508	30	116378
SCE	2017	404	97	144820
SCE	2018	266	34	133880
SCE	2019	444	30	95208
SCE	2020	218	31	127914
SCE	2021	275	6	117529
SCE	2022	250	8	168192
SDG&E	2015	25	2	51232
SDG&E	2016	48	13	13752
SDG&E	2017	28	35	107922
SDG&E	2018	21	2	53298
SDG&E	2019	26	0	26852
SDG&E	2020	28	1	25667
SDG&E	2021	29	8	44509
SDG&E	2022	29	5	20708

Source: WMP QDR 2022 Q3 and Q4 Table 6 - High wind warning overhead circuit mile days

Supporting Data for Table 5

Utility			2015	2016	2017	2018	2019	2020	2021	2022
PG&E	Ignitions	Ignitions - HFTD	62	63	101	68	62	65	66	42
		Ignitions - non- HFTD	45	45	76	57	76	63	75	59
		avg. ignition per 1000 miles - HFTD	2.51	2.55	4.09	2.75	2.51	2.63	2.67	1.70
		avg. ignition per 1000 miles - non-HFTD	0.81	0.81	1.38	1.03	1.38	1.14	1.36	1.07
	Ignition rate per outage	avg. ignition rate per outage- HFTD	0.03	0.03	0.02	0.04	0.01	0.03	0.02	0.03
		avg. ignition per outage - non-hftd	0.03	0.02	0.02	0.04	0.02	0.04	0.02	0.02
SCE	Ignitions	Ignitions – HFTD	6	5	6	5	3	3	8	7
		Ignitions - non- HFTD	7	7	10	10	10	8	12	7
		avg. ignition per 1000 miles - HFTD	0.63	0.53	0.63	0.53	0.32	0.32	0.84	0.74
		avg. ignition per 1000 miles - non-HFTD	0.25	0.25	0.35	0.35	0.35	0.28	0.42	0.25
	Ignition rate per outage	avg. ignition rate per outage- HFTD	0.06	0.03	0.03	0.05	0.02	0.03	0.09	0.10
		avg. ignition per outage - non- HFTD	0.02	0.02	0.02	0.03	0.03	0.04	0.05	0.04
SDG&E	Ignitions	Ignitions - HFTD	5	2	2	0	1	0	0	1
		Ignitions - non- HFTD	0	2	1	3	0	1	0	0

Utility			2015	2016	2017	2018	2019	2020	2021	2022
		avg. ignition per 1000 miles - HFTD	1.49	0.59	0.59	0.00	0.30	0.00	0.00	0.30
		avg. ignition per 1000 miles - non-HFTD	0.00	0.68	0.34	1.02	0.00	0.34	0.00	0.00
	Ignition rate per outage	avg. ignition rate per outage- HFTD	0.63	0.12	0.09	0.00	0.17	0.00	0.00	0.14
		avg. ignition per outage - non- HFTD	0.00	0.05	0.02	0.13	0.00	0.04	0.00	0.00

Supporting Data for Figure 5

Year	Outage Rate* when Clearance is Less Than12 ft	Outage Rate* when Clearance is Greater Than or Equal to 12 ft
2007	5.63	5.25
2008	3.15	0
2009	4.43	3.56
2010	7.25	4.97
2011	3.48	1.56
2012	2.69	1.59
2013	1.62	1.49
2014	2.59	4.41
2015	1.04	2.95
2016	1.62	1.35
2017	5.55	0
2018	2.81	3.64
2019	1.78	1.07
2020	3.02	0
2021	2.43	2.02
2022	2.96	2.12
2023	5.87	4.29
2024	1.75	2.1

*Outages Rate per 100,000 trees

Appendix B: Model Output and Interpretation

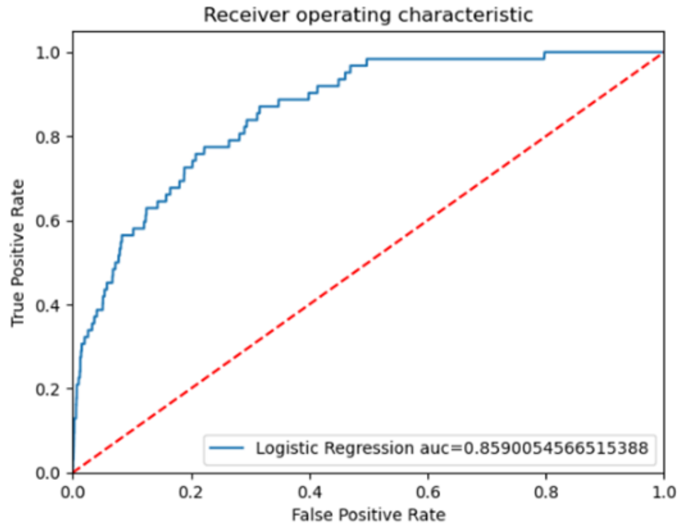
Sensitivity Analysis for Enhanced Clearance

The Vegetation Management Analytics repository contains three scripts essential for completing the dataset for sensitivity analysis. The first script retrieves and cleans vegetation management data from 2006 onwards, writing the output to S3. The second script separates outage data from other activities, linking outages to previous activities to analyze their impact on outage probability, and writes the processed data to S3. The third script prepares this data for modeling by correcting values, reducing features, and encoding variables, then generates a classification model to predict outcomes based on adjusted line clearance distances. The analysis uses Logistic Regression from scikit-learn package 1.2.0, considering factors like target species, vegetation management area, tree growth rate, Last Line Clearance Distance, Tree Diameter at Breast Height, Tree Height, Enhanced Clearance (Yes/No above 11 ft).

The sensitivity analysis examines the impact of changing line clearance distances for the test set (2023 & 2024). If the line clearance distance for a FacilityId was greater than 11 feet, it was reduced to 11 feet. The same threshold value was used to identify predicted outages versus no outages. The confusion matrix distribution from the actual test set was used to estimate potential mitigated vegetation-related outages.

Model Performance

AUC Curve



Threshold value was selected based on maximizing True Positives while also minimizing the False Positive rate (.0000700986). Used the Model that was generated from the Training dataset and Test performance on years not used for training (2023 & 2024).

2023 & 2024 Test

	Outage	No Outage	Total
Predicted Outage	47	162,971	163,018
Predicted No Outage	15	610,267	610, 282
Total	62	773,238	773,300

Accuracy: 78.9%
Recall: 75.8%
Total Observations returned with positive prediction: 21.1%
Although this model is not perfect, it does appear it is capturing risk for the trees that did experience vegetation related outage in the following year. We can change underlying data values to understand the impact a variable may have on a FacilityId's risk probability. As data is changed, for this analysis it was assumed that the distribution of Outage and No Outage across Predicted Outage and Predicted Outage would be the same.

2023 & 2024 Distribution	Outage	No Outage	Total
Predicted Outage	0.000288	.999712	163,018
Predicted No Outage	0.000025	.999975	610,282

Sensitivity Analysis

The Sensitivity Analysis was done to understand Line Clearance distance's impact on a trees risk probability score. Line Clearance Distance was changed for the Test set (2023 & 2024). If FacilityId Line Clearance >11 (enhanced clearance) then it was reduced to 11. The same threshold value (0.0000700986) was used to identify if a FacilityId in the Test Set (changed data) was Predicted Outage vs Predicted No Outage. The Confusion matrix distribution from the actual test set was used to estimate potential mitigated Vegetation related outages.

Below is the estimated impact on outages by bringing observations with enhanced clearances down to 11 feet.

2023 & 2024 Changed Data	Outage	No Outage	Total
Predicted Outage	62.8 (calculated)	217,955.2 (calculated)	218,018 (from model)
Predicted No Outage	13.9 (calculated)	555,237.1 (calculated)	555,251 (from model)
Total	76.7	733,192.3	773,300

Difference in Outages: 76.7 (Sensitivity Analysis Outage count) - 62 (Actual Outage count) = ~15 (14.7) potential mitigated outages

The same analysis was done but separately by years of data as there was significant outage differences from 2023 to 2024.

2023 & 2024 Test Performance by Year

2023 Test Performance	Outage	No Outage	Total
Predicted Outage	35	78,263	78,298
Predicted No Outage	10	308,065	308,075
Total	45	386,328	386,373

2024 Test Performance	Outage	No Outage	Total
Predicted Outage	12	84,708	84,720
Predicted No Outage	5	302,202	302,207
Total	17	386,910	386,927

Below is the percentage distribution for each group calculated from performance of the machine learning model.

2023 % Distribution	Outage	No Outage	Total
Predicted Outage	0.0004470	.999553	78,298
Predicted No Outage	0.0000326	.999968	308,075

2024 % Distribution	Outage	No Outage	Total
Predicted Outage	0.0001416	.999858	84,720
Predicted No Outage	0.0000165	.999983	302,207

Same assumed performance distribution is used to understand potential mitigated outages.

2023 Changed Data	Outage	No Outage	Total
Predicted Outage	47.5	106,271.5	106,319
Predicted No Outage	9.1	280,044.9	280,054
Total	56.6	386,316.4	386,373

2024 Changed Data	Outage	No Outage	Total
Predicted Outage	15.8	111,714.2	111,730
Predicted No Outage	4.6	275,192.4	275,197
Total	20.4	386,906.6	38,6927

By year total Predicted outage = 77, actual outage count for the same period is 62, looking at it by year this analysis shows that potential outages mitigated by enhanced clearance over two years is 15. By year this would be a difference of 11.6 outages in 2023 and 3.4 outages in 2024.