Bear Valley Electric Service 2026-2028 Wildfire Mitigation Plan

2026 Revision 0

Submitted by:

Bear Valley Electric Service, Inc.

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1. Executive Summary

Bear Valley Electric Service, Inc. (BVES or Bear Valley) is committed to the safety of our customers and the communities we serve. Bear Valley's 2026-2028 Wildfire Mitigation Plan (WMP) builds upon the significant progress in reducing wildfire and Public Safety Power Shutoff (PSPS) risk that was achieved by executing the initiatives of past WMPs and aims to further make meaningful risk reductions to utility-caused wildfires and PSPS events. The 2026-2028 WMP leverages the knowledge and experience gained and lessons learned from past WMPs, other utilities' experiences in wildfire mitigation efforts, and improvements in wildfire mitigation processes, techniques, and technologies. Continuous improvement is an essential factor in the development of the WMP.

Bear Valley's service area is in the mountain resort community of Big Bear Lake, California, with approximately 24,890 customers in a 32-square-mile service area located in the San Bernardino Mountains of Southern California, 80 miles east of Los Angeles. The region is remote and mountainous. The service area is entirely above 3,000 feet, requiring all construction to conform to the "heavy" loading standards (highest strength standard) of the California Public Utilities Commission's (CPUC) General Order 95 (GO 95). The wilderness environment with heavily treed terrain makes the territory vulnerable to potential ignition risk. The service area is considered "Very Dry" or "Dry" per the National Fire Danger Rating System (NFRDS) over 75 percent of the time. Therefore, the combination of dry conditions and heavy vegetation resulting in high levels of available fuel to burn in the event of a wildfire. The CPUC Fire-Threat Map, adopted January 19, 2018, designated Bear Valley's service area as being in the High Fire-Threat District (HFTD), with approximately 95% in Tier 2 (elevated risk) and the remaining 5% in Tier 3 (extreme risk) areas. The Cal Fire California Fire Hazard Severity Zone Map Update Project rates Bear Valley's service area as mostly "Very High Fire Hazard Severity Zone." Years of drought and elevated ambient temperatures above historical norms have only exacerbated the situation further. Climate change predictions project that increased drought, dryness, and elevated temperatures will continue their increasing trends. It is against this backdrop that BVES develops its WMP initiatives.

Primary Goal: The primary goal of Bear Valley's 2026-2028 WMP is consistent with Section 8386(a) of the California Public Utilities Code, which states each electrical corporation shall construct, maintain, and operate its electrical lines and equipment in a manner that will minimize the risk of catastrophic wildfire posed by those electrical lines and equipment. With Bear Valley's service area being entirely located within the High Fire Threat District as defined by the CPUC, Bear Valley's 2026-2028 WMP represents a comprehensive set of reasonable wildfire mitigation initiatives aimed at building upon the substantial wildfire prevention and mitigation work accomplished in prior WMPs to further reduce wildfire risk and reduce the frequency and impacts of PSPS events.

Plan Objectives: The primary objective of Bear Valley's 2026-2028 WMP is to reduce the risk of utility-caused wildfire and to reduce frequency and impacts of PSPS events. This WMP implements 60 mitigation initiatives to achieve this objective over the period of 2026 to 2028 by addressing Bear Valley's highest-priority wildfire risk drivers. Specifically, the initiatives will:

- Reduce the likelihood of ignitions due to objects making contact with power lines by hardening the higher risk areas of the overhead distribution system with covered conductor.
- Reduce the likelihood of ignitions by maintaining vegetation clearance distances for trees and vegetation from overhead facilities that could potentially contact power lines by executing a comprehensive vegetation inspection program and vegetation line clearance and hazard tree removal program.
- Reduce the likelihood that equipment will fail and lead to an ignition by executing a comprehensive asset maintenance and inspection program.
- Reduce the likelihood of ignitions by optimizing fault protection device settings for wildfire mitigation while balancing reliability impacts to customers.
- Deploy new technologies aimed at providing continuous system monitoring and ignition detection capability to reduce the likelihood of an ignition leading to a wildfire.
- Reduce the impact of Southern California Edison (SCE) invoked PSPS on power lines that supply the BVES service area by pursuing solar generation and battery facilities within the BVES service area.
- Prioritize the deployment of mitigation initiatives to the areas that have the greatest potential for wildfire and PSPS.
- Continue to pursue improvements in risk modeling and weather forecasting capabilities to better inform wildfire mitigation strategies, to better understand impacts of climate change on wildfire and PSPS risk, and to assist with day-to-day operational decisions to mitigate the risk of ignitions.
- Reduce the impacts of PSPS to customers, particularly our Access and Functional Needs customers, by implementing programs aimed at providing improved customer support and communications during PSPS events.
- Reduce likelihood of widespread PSPS by eliminating all bare wire power lines from the sub-transmission system, ensuring areas within distribution circuits with a higher risk of PSPS can be sectionalized, and utilizing improved fire risk modeling and weather forecasting to reduce PSPS scope.
- Reduce impacts to customers, stakeholders, and local government and agency partners by maintaining an effective emergency response and disaster response plan and ensuring staff are proficient at implementing and executing its procedures.
- Improve wildfire mitigation plan initiative implementation efficiency and effectiveness by leveraging information technology solutions including enterprise systems where possible.

Framework: Public safety is Bear Valley's highest priority. Bear Valley's 2026-2028 WMP builds upon continued effort and investment underway at BVES, and progress realized to reduce the probability of utility-caused ignitions, reduce the risk of utility-caused wildfire, and reduce frequency and impacts of PSPS events. This WMP incorporates areas for continued improvement, lessons learned from implementing previous WMPs, and knowledge gained through collaborative efforts with other electric utilities. Additionally, this WMP includes more data, quantitative content, and increased sophistication in risk modeling to develop and deploy mitigation initiatives to achieve the plan's primary goal and primary objectives.

To date, BVES has not experienced any ignition events or conditions that would have caused it to activate any PSPS to mitigate wildfire threats during the 2023-2025 WMP period. Bear Valley maintains its facilities with a foundational understanding of natural resource management in an area surrounded by mountainous terrain and forested slopes. To sustain its record of success, Bear Valley worked collaboratively with public safety partners and state and federal agencies to enhance its preparation to face the ever-evolving threat of catastrophic wildfires. Bear Valley has not experienced an ignition in over 20 years and its facilities have never caused a wildfire.

Despite an absence of utility-caused ignitions or PSPS events, BVES recognizes the risk of ignitions and PSPS events are still significant and, therefore, embraces wildfire safety as a core competency in executing work, adopting fire operational standards, and continuously monitoring system and environmental conditions. BVES directed its resources to the most cost-effective projects to bring down the risk while aiming to promote resilience and maintain affordability and reliability. Specifically, BVES aims to (1) improve its understanding of the wildfire risk posed by and to its systems; (2) focus on reducing the highest risks aggressively and efficiently; and (3) maximize scarce financial and human resources in its efforts to mitigate wildfire risks. BVES also recognizes the significant impact climate change is having on increasing the risk of wildfires. BVES must continue to push forward with progress on its WMP initiatives to prevent potential future ignitions and wildfires, and avoid reliance on PSPS as an ignition mitigation tool.

Bear Valley's most impactful risk reduction initiatives are its large grid hardening initiatives, specifically overhead facilities hardening and installation of covered conductor. Since its first WMP in 2019, Bear Valley has achieved and, in some cases, exceeded its stated grid hardening targets and accomplished the following grid hardening construction work:

- Replaced 23.9 circuit miles of sub-transmission bare wire with molded covered conductor. At the start of 2019, it was 97.0 percent bare wire. At the end of 2024, 16.8 percent of the sub-transmission system was bare wire.
- Replaced 43.9 circuit miles of distribution bare wire with molded covered conductor. At the start of 2019, it was 77.4 percent bare wire. At the end of 2024, 58.7 percent of the distribution system was bare wire.
- Conducted 1,813 pole replacements, including installing 328 lightweight steel poles, 138 fire-resistant composite poles and 73 ductile iron poles.
- Remediated 290 wood poles.
- Installed fire-resistant wire mesh on 2,999 wood poles. At the end of 2024, 3,538 poles were hardened for evacuation. Additionally, all primary evacuation routes from the service area have been hardened for evacuation.

- Removed 862 tree attachments. At the end of 2024, 345 tree attachments remain in the Bear Valley's system.
- Removed all expulsion fuses from its system by replacing 3,114 expulsion fuses with 536 electronic fuses (Fuse TripSavers) and 2,578 current limiting fuses.

Bear Valley adopted a robust array of asset and vegetation management inspections that appropriately go beyond the minimum CPUC requirements and leverage advanced inspection technologies to reduce ignition risk. Each year Bear Valley conducts a comprehensive LiDAR, Aerial (UAV) High-Definition Photography and Videography, UAV Thermography, and satellite inspection of its entire overhead system. These are in addition to General Order 165 detailed inspections and two full patrol inspections – one by an independent third party – and intrusive pole inspections utilizing non-destructive IML-RESI PowerDrill Pole Inspection Technology. Additionally, all vegetation clearance activities are 100 percent inspected by a certified arborist.

In addition to the inspections discussed above, Bear Valley has continued to execute a vegetation clearance program that appropriately goes beyond the minimum CPUC clearance requirements in accordance with best practice and standards. BVES continues to maintain a contracted full-time certified arborist embedded on staff to assist in vegetation management decision-making and inspection. Additionally, BVES has greatly improved its vegetation enterprise system that provides for accurate GIS and photographic documentation of all tree trimming activities and establishes a database that includes tree species, tree health, date trimmed, and growth rate. Since 2019, Bear Valley has removed or remediated 949 trees that posed high fall-in risk to power lines.

BVES has made significant advancements in its risk modeling capabilities to optimize the identification of areas of highest wildfire risk and PSPS vulnerability. These efforts have helped BVES better inform its selection of wildfire mitigation initiatives and prioritization of grid hardening and inspections. In the past four years, BVES progressively implemented probabilistic risk modeling capabilities. In 2020, BVES engaged REAX Engineering to develop full field-effect wildfire probability and consequence maps for 2021 and 2050. In 2022, BVES implemented Technosylva's Wildfire Analyst Enterprise (WFA-E) model, and in 2023, BVES implemented Technosylva's FireSight (formerly Wildfire Risk Reduction Model (WRRM)) model. In 2024, BVES implemented a Fire Potential Index (FPI) calculation developed by Technosylva. Also, during 2024, BVES engaged Direxyon to develop a utility risk model that evaluates ignition risk and PSPS risk by drawing inputs from the Technosylva models, Bear Valley's asset databases, inspection results, and customer information system. The Direxyon model will also help BVES to evaluate cost in relation to risk reduction as well as evaluate alternate mitigation strategies, helping optimize long-term strategic planning to reduce wildfire risk.

BVES has further enhanced its situational awareness through the installation of fault indicators, the use of remote cameras to allow for autonomous monitoring of the power line infrastructure and alert crews to potentially hazardous events automatically, the use of continuous monitor sensors on circuits to provide usable grid information and alert crews to potential problems that could develop into faults and ignitions, and the development and implementation of a Fire Potential Index (FPI).

Bear Valley has updated its PSPS Procedures and exercised them through Table Top Exercises and Full-Scale Exercises. The PSPS Procedures were updated to include Bear Valley's FPI, which was implemented at the start of 2024.

Recent wildfire events in Southern California, including the Line Fire, the Eaton Fire and the Palisades Fire and the effects of climate change now and projected, highlight that it is imperative that Bear Valley build upon its previous accomplishments achieved in prior WMPs and the knowledge gained from collaborating with other utilities by implementing the initiatives in this 2026-2028 WMP, which are designed to further reduce the probability of utility-caused ignitions, reduce the risk of utility-caused wildfire, and to reduce frequency and impacts of PSPS events.

2. Responsible Persons

Paul Marconi, President, Treasurer, and Secretary at BVES is the executive-level owner with overall responsibility for this Wildfire Mitigation Plan. BVES Table 2-1 provides 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 BVES through the following email address: WMP@bvesinc.com. This group email address includes the staff in the table below and Bear Valley's Regulatory Affairs staff.

BVES Table 2-1 WMP Responsible Persons

WMP Section	Name	Title	Email	Phone Number
1. Executive Summary	Paul Marconi	President, Treasurer, & Secretary	Paul.Marconi@bvesinc.com	909-202-9539
2. Responsible Persons	Paul Marconi	President, Treasurer, & Secretary	Paul.Marconi@bvesinc.com	909-202-9539
3. Overview of WMP	Paul Marconi	President, Treasurer, & Secretary	Paul.Marconi@bvesinc.com	909-202-9539
4. Overview of the Service Territory	Tom Chou	Utility Engineer & Wildfire Mitigation Supervisor	Tom.Chou@bvesinc.com	909-273-8009
5. Risk Methodology and Assessment	Alexis Ravnik	Electric Distribution Systems Engineer	Alexis.Ravnik@bvesinc.com	909-649-5379
6. Wildfire Mitigation Strategy Development	Tom Chou	Utility Engineer & Wildfire Mitigation Supervisor	Tom.Chou@bvesinc.com	909-273-8009
7. Public Safety Power Shutoff	Sean Matlock	Energy Resource Manager & Assistant Corporate Secretary	Sean.Matlock@bvesinc.com	909-522-1913
8. Grid Design, Operations, and Maintenance	Tom Chou	Utility Engineer & Wildfire Mitigation Supervisor	Tom.Chou@bvesinc.com	909-273-8009
9. Vegetation Management and Inspections	Jared Hennen	Wildfire Mitigation and Reliability Engineer	Jared.Hennen@bvesinc.com	909-255-2948
10. Situational Awareness and Forecasting	Tom Chou	Utility Engineer & Wildfire Mitigation Supervisor	Tom.Chou@bvesinc.com	909-273-8009
11. Emergency Preparedness, Collaboration, and Public Awareness	Paul Marconi	President, Treasurer, & Secretary	Paul.Marconi@bvesinc.com	909-202-9539

12. Enterprise Systems	Tom Chou	Utility Engineer & Wildfire Mitigation Supervisor	Tom.Chou@bvesinc.com	909-273-8009
13. Lessons Learned	Paul Marconi	President, Treasurer, & Secretary	Paul.Marconi@bvesinc.com	909-202-9539

3. Overview of Base WMP

3.1 Primary Goal

In accordance with Section 8386(a) of the California Public Utilities Code, BVES 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. With its service area being entirely located within the High Fire Threat District (HFTD) as defined by the California Public Utilities Commission (CPUC), Bear Valley's 2026-2028 WMP represents a comprehensive set of reasonable wildfire mitigation initiatives aimed at building upon the substantial wildfire prevention and mitigation work accomplished in prior WMPs to further reduce wildfire risk and reduce the frequency and impacts of Public Safety Power Shutoff (PSPS) events.

3.2 Plan Objectives

The primary objective of Bear Valley's 2026-2028 WMP is to reduce the risk of utility-caused wildfire and to reduce frequency and impacts of PSPS events. This WMP implements 60 mitigation initiatives to achieve this objective over the period of 2026 to 2028 by addressing Bear Valley's highest-priority wildfire risk drivers. Specifically, the initiatives will:

- Reduce the likelihood of ignitions due to objects making contact with power lines by hardening the higher risk areas of the overhead distribution system with covered conductors.
- Reduce the likelihood of ignitions by maintaining vegetation clearance distances for trees and vegetation from overhead facilities that could potentially contact power lines by executing a comprehensive vegetation inspection program and vegetation line clearance and hazard tree removal program.
- Reduce the likelihood that equipment will fail and lead to an ignition by executing a comprehensive asset maintenance and inspection program.
- Reduce the likelihood of ignitions by optimizing fault protection device settings for wildfire mitigation while balancing reliability impacts to customers.
- Deploy new technologies aimed at providing continuous system monitoring and ignition detection capability to reduce the likelihood of an ignition leading to a wildfire.
- Reduce the impact of Southern California Edison (SCE) invoked PSPS on power lines that supply the BVES service area by pursuing solar generation and battery facilities within the BVES service area.
- Prioritize the deployment of mitigation initiatives to the areas that have the greatest potential for wildfire and PSPS.
- Continue to pursue improvements in risk modeling and weather forecasting capabilities to better inform wildfire mitigation strategies, to better understand impacts of climate change on wildfire and PSPS risk, and to assist with day-to-day operational decisions to mitigate the risk of ignitions.

- Reduce the impacts of PSPS events to customers, particularly our Access and Functional Needs customers, by implementing programs aimed at providing improved customer support and communications during PSPS events.
- Reduce the likelihood of widespread PSPS by eliminating all bare wire power lines from the sub-transmission system, ensuring areas within distribution circuits with a higher risk of PSPS can be sectionalized, and utilizing improved fire risk modeling and weather forecasting to reduce PSPS scope.
- Reduce impacts to customers, stakeholders, and local government and agency partners by maintaining an effective emergency response and disaster response plan and ensuring staff are proficient at implementing and executing its procedures.
- Improve wildfire mitigation plan initiative implementation efficiency and effectiveness by leveraging information technology solutions, including enterprise systems, where possible.

3.3 Utility Mitigation Activity Tracking IDs

Bear Valley has assigned unique “Utility Initiative Tracking IDs” (Tracking IDs) for each initiative in this WMP. **BVES Table 3-1 Utility Tracking IDs lists the Tracking IDs** for each initiative.

BVES Table 3-1 Utility Tracking IDs

UTILITY INITIATIVE TRACKING ID	UTILITY INITIATIVE NAME	WMP INITIATIVE CATEGORY	WMP INITIATIVE
EP_1	Emergency preparedness and recovery plan	Emergency Preparedness and Community Outreach	Emergency preparedness and recovery plan
EP_2	External collaboration and coordination	Emergency Preparedness and Community Outreach	External collaboration and coordination
EP_3	Public communication, outreach, and education	Emergency Preparedness and Community Outreach	Public communication, outreach, and education
EP_4	Customer support in wildfire and PSPS emergencies	Emergency Preparedness and Community Outreach	Customer support in wildfire and PSPS emergencies
ENT_1	Asset management and inspection enterprise system(s)	Enterprise Systems	Summary of Enterprise Systems
ENT_2	Vegetation management enterprise system	Enterprise Systems	Summary of Enterprise Systems
GD_1	Covered Conductor Replacement Project (Reconductor)	Grid Design, Operations, and Maintenance	Covered conductor installation
GD_10	Fuse TripSaver Automation	Grid Design, Operations, and Maintenance	Installation of system automation equipment
GD_11	Non-Exempt Surge Arrester Replacement	Grid Design, Operations, and Maintenance	Other grid topology improvements to minimize risk of ignitions
GD_12	Tree Attachment Removal Project	Grid Design, Operations, and Maintenance	Other grid topology improvements to minimize risk of ignitions
GD_13	Safety and Technical Upgrades to Lake Substation	Grid Design, Operations, and Maintenance	Other technologies and systems not listed above
GD_14	Partial Safety and Technical Upgrades to Village Substation	Grid Design, Operations, and Maintenance	Other technologies and systems not listed above
GD_15	Equipment maintenance and repair	Grid Design, Operations, and Maintenance	Equipment maintenance and repair

GD_16	Asset Quality assurance / quality control	Grid Design, Operations, and Maintenance	Quality assurance / quality control
GD_17	Asset Open work orders	Grid Design, Operations, and Maintenance	Work orders
GD_18	Equipment Settings to Reduce Wildfire Risk	Grid Design, Operations, and Maintenance	Equipment Settings to Reduce Wildfire Risk
GD_19	Grid Response Procedures and Notifications	Grid Design, Operations, and Maintenance	Grid Response Procedures and Notifications
GD_2	Minor Undergrounding Upgrades Projects	Grid Design, Operations, and Maintenance	Undergrounding of electric lines and/or equipment
GD_20	Personnel Work Procedures and Training in Conditions of Elevated Fire Risk	Grid Design, Operations, and Maintenance	Personnel Work Procedures and Training in Conditions of Elevated Fire Risk
GD_21	Asset Workforce Planning	Grid Design, Operations, and Maintenance	Workforce Planning
GD_22	Detailed Inspections	Grid Design, Operations, and Maintenance	Asset inspections
GD_23	Patrol Inspections	Grid Design, Operations, and Maintenance	Asset inspections
GD_24	UAV Thermography Inspections	Grid Design, Operations, and Maintenance	Asset inspections
GD_25	UAV HD Photography/Videography Inspections	Grid Design, Operations, and Maintenance	Asset inspections
GD_26	Third-Party Ground Patrol Inspections	Grid Design, Operations, and Maintenance	Asset inspections
GD_27	Intrusive Pole Inspections	Grid Design, Operations, and Maintenance	Asset inspections
GD_28	Substation inspections	Grid Design, Operations, and Maintenance	Asset inspections
GD_3	Covered Conductor Replacement Project (Pole Assessment)	Grid Design, Operations, and Maintenance	Distribution pole replacements and reinforcements

GD_4	Evacuation Route Hardening Project	Grid Design, Operations, and Maintenance	Distribution pole replacements and reinforcements
GD_5	Traditional overhead hardening	Grid Design, Operations, and Maintenance	Traditional overhead hardening
GD_6	Bear Valley Solar Energy Project	Grid Design, Operations, and Maintenance	Microgrids
GD_7	Bear Valley Energy Storage Project	Grid Design, Operations, and Maintenance	Microgrids
GD_8	Switch and Field Device Automation	Grid Design, Operations, and Maintenance	Installation of system automation equipment
GD_9	Capacitor Bank Upgrade Project	Grid Design, Operations, and Maintenance	Installation of system automation equipment
RMA_1	Risk Methodology and Assessment	Risk Methodology and Assessment	Risk Methodology and Assessment
SAF_1	Advanced weather monitoring and weather stations	Situational Awareness and Forecasting	Environmental monitoring systems
SAF_2	Install Fault Indicators	Situational Awareness and Forecasting	Grid monitoring systems
SAF_3	Online Diagnostic System	Situational Awareness and Forecasting	Grid monitoring systems
SAF_4	Autonomous Monitoring of Power Line Infrastructure	Situational Awareness and Forecasting	Ignition detection systems
SAF_5	ALERT Wildfire Cameras	Situational Awareness and Forecasting	Ignition detection systems
SAF_6	Weather forecasting	Situational Awareness and Forecasting	Weather forecasting
SAF_7	Fire potential index	Situational Awareness and Forecasting	Fire potential index
VM_1	Detailed Inspections	Vegetation Management and Inspection	Vegetation management inspections
VM_10	Pole clearing	Vegetation Management and Inspection	Pole clearing

VM_11	Wood and slash management	Vegetation Management and Inspection	Wood and slash management
VM_12	Substation defensible space	Vegetation Management and Inspection	Defensible space
VM_13	Emergency response vegetation management	Vegetation Management and Inspection	Activities based on weather conditions
VM_14	Post-fire service restoration	Vegetation Management and Inspection	Post-fire service restoration
VM_15	Vegetation Management Quality assurance / quality control	Vegetation Management and Inspection	Quality assurance / quality control
VM_16	Vegetation Management Open work orders	Vegetation Management and Inspection	Work orders
VM_17	Vegetation Management Workforce planning	Vegetation Management and Inspection	Workforce Planning
VM_2	Patrol Inspections	Vegetation Management and Inspection	Vegetation management inspections
VM_3	UAV HD Photography/Videography Inspections	Vegetation Management and Inspection	Vegetation management inspections
VM_4	LiDAR Inspections	Vegetation Management and Inspection	Vegetation management inspections
VM_5	Third-Party Ground Patrol Inspections	Vegetation Management and Inspection	Vegetation management inspections
VM_6	Substation inspections	Vegetation Management and Inspection	Vegetation management inspections
VM_7	Satellite Imaging Inspections	Vegetation Management and Inspection	Vegetation management inspections
VM_8	Fall-in Mitigation and High-risk Species	Vegetation Management and Inspection	Pruning and Removal
VM_9	Clearance	Vegetation Management and Inspection	Pruning and Removal
WMSD_1	Wildfire Mitigation Strategy Development	Wildfire Mitigation Strategy Development	Wildfire Mitigation Strategy Development

3.4 Prioritized List of Wildfire Risks and Risk Drivers

The identification of prioritizing of wildfire risk across the BVES service territory would typically involve the integrated examination of environmental events and equipment failures throughout the system, together with the details of any resulting fire events. This operating experience data could be examined statistically to provide a data-driven characterization of the relative ignition and wildfire likelihood. However, the BVES system has not yet experienced any ignition or wildfire events so such a data-driven approach cannot be directly used to establish a prioritization scheme for risk drivers. Therefore, to prioritize the risks and risk drivers in **Table 3-1. List of Risks and Risk Drivers to Prioritize**, the following process was used.

The readily available data for examination consists of 24 years of outage history for the BVES system. The data consists of approximately 1,200 events that have occurred. This data was organized based on the risk drivers in **Table 3-1**. However, since there have been no ignition or wildfire events in the BVES system, there is no direct mechanism to establish a relative fire occurrence likelihood. Although no ignition events have occurred, a statistical approach (Jeffery's Un-informed Prior) can be used to estimate the probability that an ignition event occurs as the result of an environmental or equipment failure event. This approach simply assumes that the next environmental or equipment failure event has a 50/50 chance of occurring and yields an ignition or wildfire occurrence probability of approximately 4.2E-04.

$$\frac{0.50}{1{,}200} \sim 4.2E - 04$$

The CPUC requires utilities to report ignitions involving their equipment that meet the following criteria:

1. A self-propagating fire of material other than electrical and/or communication facilities; and
2. The resulting fire traveled greater than one linear meter from the ignition point; and
3. The utility has knowledge that the fire occurred.

This data was also organized based on the risk drivers in **Table 3-1**. This data consists of approximately 5,600 fire events. However, there is no publicly available source to ascertain the total number of events that occurred on those systems (e.g., events that did not result in a reportable ignition) organized to the same level of detail in Table 3-1. Therefore, this data cannot be used directly to ascertain the likelihood (probability) that an ignition or wildfire occurs given an environmental or equipment failure event. However, the manipulation of this dataset does yield an empirical basis to establish the relative likelihood of the occurrence of fires due to each of the risk drivers in **Table 3-1**.

As identified above, BVES has not had any environmental or equipment failure events that have led to an ignition, so the number of outages (potential precursor event) is reported in the "x% of ignition in HFTD.

The combination of these two sources of data was used to develop a relative likelihood (probability) of an ignition or wildfire event occurring in the BVES service territory for each of the risk drivers in **Table 3-1**. The resulting probability values for each of the risk drivers vary from about 1E-04 to less than 1E-07. A qualitative risk ranking was assigned to each of the risk drivers using the following probability metrics:

Ignition or Wildfire Occurrence Probability - P_i	Risk Rank
$P_i \geq 1.0E\text{-}05$	HIGH
$1.0E\text{-}05 > P_i \geq 1.0E\text{-}06$	MEDIUM
$1.0E\text{-}06 > P_i$	LOW

Bear Valley's service area is a small, mountain environment, heavily wooded, and located entirely within the HFTD. Most assets are at approximately 7,000 feet. Some facilities are located on slopes. The service area has a fairly low population density and animal life is active. Temperatures are cold to moderate and the air is fairly clean (low salinity). Precipitation can be high with an average snow fall of 58 inches per year. Lightning activity is high during the summer monsoon season and winds can be high during winter storms. These topographical and climatological risk factors are essentially homogenous across the entire service area due to the small size of the service area and apply fairly evenly to the risk drivers of Table 3-1. Specific Topographical and Climatological Risk Factors are listed in Table 3-1 where they may be an important factor to the risk driver.

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

Priority	Risk	Risk Driver	x% of ignitions in HFTD	Topographical and Climatological Risk Factors
Medium	Contact from object	Animal contact	1.7%	Service area mostly WUI
Medium	Contact from object	Balloon contact	0.3%	None
High	Contact from object	Land vehicle contact	8.6%	None

Medium	Contact from object	Aircraft vehicle contact	0.3%	Airport in close proximity to facilities
Medium	Contact from object	3rd party contact	1.6%	None
Medium	Contact from object	Other contact from object	0.4%	None
Low	Contact from object	Unknown	0.0%	None
High	Vegetation contact	Fall-in (branch failure)	6.9%	Heavy vegetation
High	Vegetation contact	Fall-in (trunk failure)	9.7%	Heavy vegetation
Low	Vegetation contact	Fall-in (root failure)	0.0%	Heavy vegetation
High	Vegetation contact	Blow-in	9.6%	Heavy vegetation
Medium	Vegetation contact	Grow-in	1.0%	Heavy vegetation
Low	Equipment / facility failure or damage	Anchor/guy	0.0%	None
Low	Equipment / facility failure or damage	Capacitor bank	0.1%	None
Medium	Equipment / facility failure or damage	Conductor	1.7%	None
High	Equipment / facility failure or damage	Connector device	7.5%	None
Low	Equipment / facility failure or damage	Cross arm	0.1%	None

High	Equipment / facility failure or damage	Fuse	11.9%	None
Medium	Equipment / facility failure or damage	Cutout	2.3%	None
Low	Equipment / facility failure or damage	Insulator and bushing	0.2%	Lightning storms
Low	Equipment / facility failure or damage	Lightning arrestor	0.1%	Lightning storms
Medium	Equipment / facility failure or damage	Pole	0.4%	None
Medium	Equipment / facility failure or damage	Recloser	0.7%	None
Low	Equipment / facility failure or damage	Relay	0.0%	None
Medium	Equipment / facility failure or damage	Sectionalizer	1.3%	None
Medium	Equipment / facility failure or damage	Splice	0.3%	None
Medium	Equipment / facility failure or damage	Switch	0.5%	None
Low	Equipment / facility failure or damage	Tap	0.0%	None
Low	Equipment / facility failure or damage	Tie wire	0.1%	None
High	Equipment / facility failure or damage	Transformer	3.4%	None
Medium	Equipment / facility failure or damage	Voltage regulator/booster	0.5%	None

Medium	Equipment / facility failure or damage	Unknown	1.0%	None
High	Equipment / facility failure or damage	Other	2.7%	None
High	Wire-to-wire contact	Wire-to-wire contact	3.3%	High winds
Low	Contamination	Contamination	0.0%	None
Low	Protective device operation	Protective device operation	0.0%	None
Low	Vandalism/ theft	Vandalism/ theft	0.2%	None
High	Lightning	Lightning	21.4%	Lightning storms
Low	Unknown	Unknown	0.0%	None
Medium	Dig-in	Dig-in	0.5%	None

3.5 Performance Metrics

The performance metrics, including initiative targets that Bear Valley reports to Energy Safety per the Energy Safety Data Guidelines, are comprehensive and allow Bear Valley to evaluate the effectiveness of this WMP. Therefore, Bear Valley does not have any additional self-identified performance metrics for **Table 3 2 Self-Identified Performance Metrics.**

Table 3-2 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)
None	N/A	N/A

3.6 Projected Expenditures

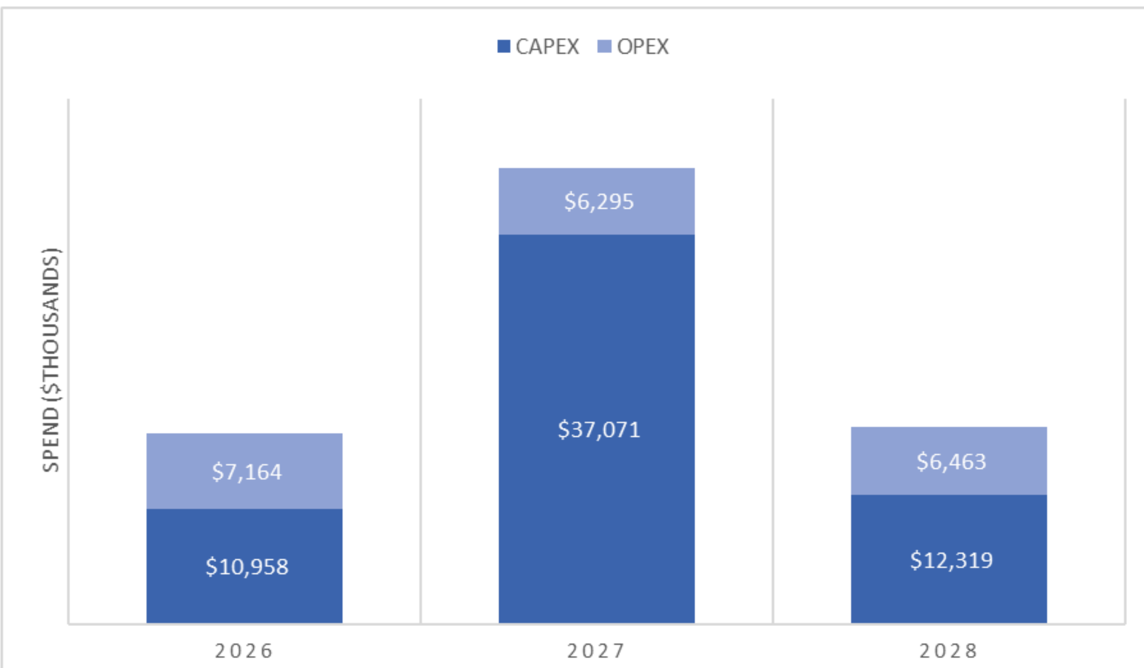
Table 3-3 Summary of Projected WMP Expenditures provides Bear Valley's projected expenditures by year to execute the initiatives of this WMP.

Table 3-3 Summary of Projected WMP Expenditures

Year of WMP Cycle	Spend (thousands $USD)
2026	$18,122
2027	$45,256
2028	$18,782

BVES Figure 3-1 Summary of Projected WMP Expenditures provides a summary graphic of Bear Valley's projected expenditures by year to execute the initiatives of this WMP.

BVES Figure 3-1 Summary of Projected WMP Expenditures



The larger spend in 2027 is due to the projected CAPEX spend for two major projects designed to reduce PSPS risk. They are:

- Bear Valley Solar Energy Project GD_6 ($17,162 thousand)

- Bear Valley Energy Storage Project GD_7 ($10,838 thousand)

Without these projects, the CAPEX spend for 2027 is projected to be $10,961 thousand and the overall spend for 2027 is projected to be $17,256 thousand.

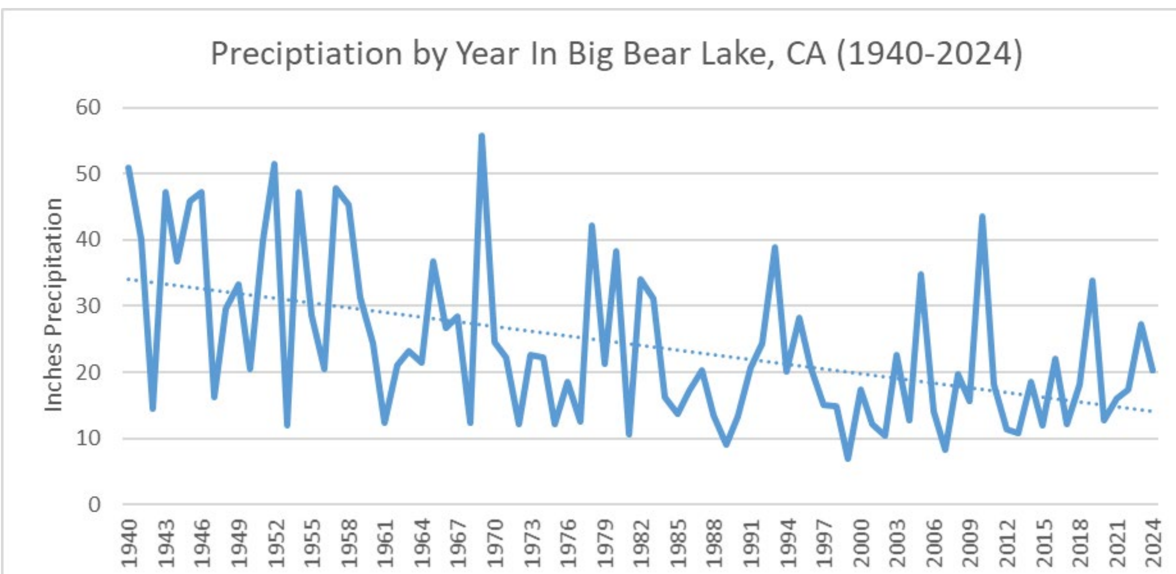
3.7 Climate Change

San Bernardino County's Climate Change Vulnerability Assessment[1] notes that

> "As temperatures increase and precipitation levels decline, it is expected that wildfires will be more frequent and of greater intensity. Additionally, individual fires are expected to be larger. The mountain region of the county faces the greatest risk…"

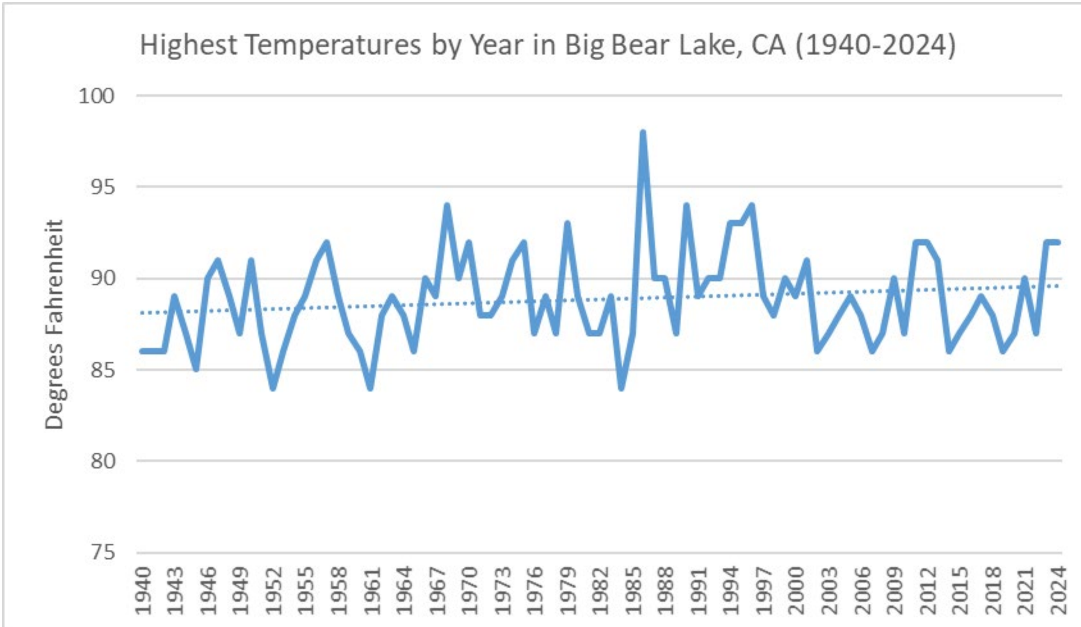
Figure 3-1 Precipitation in Big Bear Lake by Year and **Figure 3-2 Highest Temperatures in Big Bear Lake by Year** show that Big Bear Lake is experiencing decreased precipitation over time and increased high temperature over time.

Figure 3-1 Precipitation in Big Bear Lake by Year



[1] County of San Bernardino Climate Change Vulnerability Assessment, November 2018, https://countywideplan.com/wp-content/uploads/sites/68/2021/02/CAR_VA_CWP_221-223_ClimChngVulnAssess_FinalDraft_20181127.pdf

Figure 3-2 Highest Temperatures in Big Bear Lake by Year



Bear Valley's WMP is designed to consider that the environmental conditions that make its service area vulnerable to catastrophic wildfire are expected to worsen over time as a result of climate change. Figure 3-2 clearly indicates that Bear Valley is experiencing a steady decline in precipitation, which indicates droughts are more frequent and fuels are more likely to be dryer. Figure 3-3 shows temperature is steadily increasing, which creates the conditions for dryer fuels. These factors increase the risk of catastrophic wildfire in the Bear Valley service area. Therefore, Bear Valley is not only focused on assessing the current wildfire risk given current environmental conditions but also looks at future wildfire risk given worsening environmental conditions with respect to wildfire potential.

In running the Technosylva FireSight model (quantifies risk from each asset), Bear Valley had Technosylva use future (2030) projected fuels and environmental conditions so that the wildfire mitigation planning is forward-looking and includes the impact of dynamic climate change in the selection and implementation of WMP initiatives. Because the grid hardening mitigations have a long-lasting impact on ignition risk reduction and the planning and implementation timelines for grid hardening initiatives are lengthy, it is appropriate to use projected future environmental conditions in line with climate change.

4. Overview of the Service Territory

4.1 Service Territory

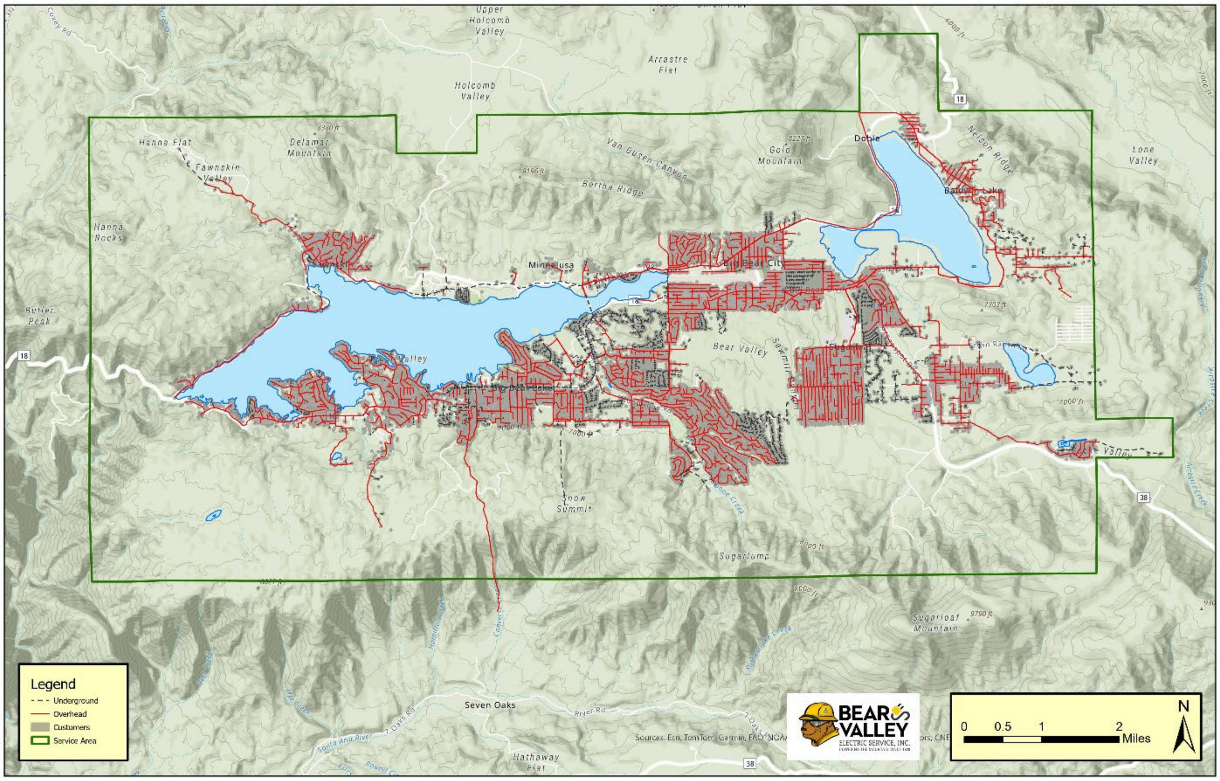
Table 4-1 High-Level Service Territory Components provides a high-level overview of Bear Valley's service territory components.

Table 4-1 High-Level Service Territory Components

Characteristic	HFTD Tier 2	HFTD Tier 3	Non-HFTD	Total
Area served (sq. mi.)	30.6	1.4	0	32
Number of customers served	24786	1	0	24787
Overhead transmission lines (circuit miles)	0	0	0	0
Overhead distribution lines (circuit miles)	203.93	1.56	0	205.49
Underground transmission lines (circuit miles)	0	0	0	0
Underground distribution lines (circuit miles)	62.03	0	0	62.03

Figure 4-1 High-Level Service Territory Components provides a high-level graphic of Bear Valley's service territory components.

Figure 4-1 High-Level Service Territory Components



4.2 Catastrophic Wildfire History

Bear Valley has not experienced any electrical corporation ignited fires; therefore, Bear Valley does not have information for **Table 4-2 Catastrophic Electrical Corporation Wildfires.**

Table 4-2 Catastrophic Electrical Corporation Wildfires

Ignition Date	Fire Name	Official Cause	Fire Size (acres)	No. of Fatalities	No. of Structures Destroyed and Damaged	Financial Loss (US$)	Lesson(s) Learned
None	N/A	N/A	N/A	N/A	N/A	N/A	N/A

4.3 Frequently Deenergized Circuits

Bear Valley has not experienced the threshold conditions that would cause it to invoke a PSPS; therefore, Bear Valley has not invoked a PSPS ever and does not have information for **Table 4-3 Frequently Deenergized Circuits.** BVES does not have a map of frequently deenergized circuits since it has not deenergized any circuits.

Table 4-3 Frequently Deenergized Circuits

Entry #	Circuit ID	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
None	N/A	N/A	N/A	N/A	N/A	N/A

5. Risk Methodology and Assessment

This section of the WMP describes the overall risk methodology for wildfire risk and outage program risk, key input data, assumptions, and risk results that inform the overall mitigation strategy and prioritization of initiatives discussed in Section 6.0. The service territory for BVES is all designated as a Tier 2 HFTD, except for a small section which is designated as a Tier 3 HFTD. Therefore, the entirety of BVES' service territory is vulnerable to utility ignitions and wildfires. Due to the inherent risk across the utility footprint, there is significantly less risk variation between lines and circuits than other California IOUs. Therefore, BVES's risk scoring necessarily incorporates this understanding. Further, BVES seeks to be prudent with its ratepayer funds and is closely observing its fellow utilities and monitoring their developments as it pertains to risk methodology and assessment. Bear Valley continues to adopt, implement, and update appropriate risk methodologies, assessments, and modeling where such approaches and tools allow BVES to gain a better understanding of the risks and how those risks should be mitigated.

5.1 Methodology

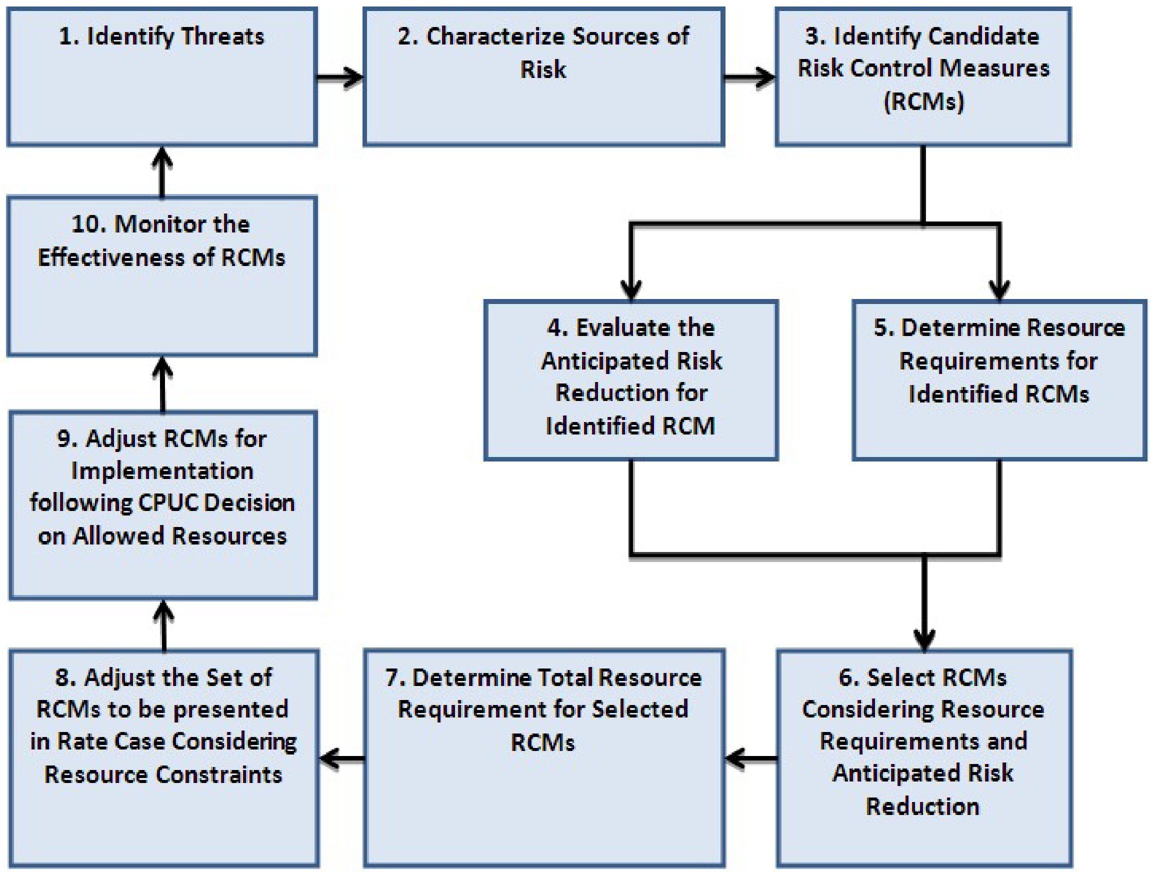
5.1.1 Overview

The following subsections provide 1) a brief narrative describing the current methodology BVES employs to quantify overall utility risk, wildfire risk, and outage program risk, and 2) an overview of the in-process transition to a probabilistic method that will allow BVES to make data-driven decisions aimed at reducing wildfire risk and minimizing exposure to outage risk events.

5.1.1.1 Current Methodology

BVES evaluates enterprise risk in accordance with a Risk-Based Decision-Making Framework that aligns with the safety model approach for Small and Multi-Jurisdictional Utilities (SMJU) provided in CPUC D.19-04-020 issued May 6, 2019. This approach to risk management includes the basic tenets of the International Standardization Organization's "Risk Management – Principles and Guidelines" ("ISO 31000"). Specifically, the process utilizes the Cycle Ten-Step Approach to perform the risk analysis as summarized in BVES Figure 5-1.

BVES Figure 5-1 Cycle Ten-Step Approach



This Risk Register evaluates the enterprise risk reduction relative to the cost of the mitigation using the Risk Spend Efficiency (RSE) analysis. This analysis focuses on a review of ongoing and potential new projects to mitigate the three primary risk events:

- Wildfire – Threats to Public Safety
- Wildfire – Significant Loss of Property
- PSPS – Loss of Energy Supplies

The enterprise risk evaluation considers a reasonable worst-case scenario for the three primary risk events. For each primary risk event, BVES determined the frequency of occurrence and impact scores using a qualitative risk assessment tool that utilizes a 7x7 logarithmic score matrix to assess risk based on the following factors:

- Personal and public safety
- System reliability impacts
- Regulatory compliance and legal implications
- Quality of service to customers
- Environmental impacts

The overall risk is a weighted average across the risk factors as described in Section 5.2.2. The Risk Register quantifies the total unmitigated risk score (i.e., no mitigation initiatives implemented) and the mitigated risk score (i.e., mitigation initiative implemented) for each mitigation initiative. The overall risk reduction (i.e., risk benefit) is the difference between the unmitigated risk and the mitigated risk. Additionally, the RSE is calculated as the ratio of the risk benefit and the annual cost for the mitigation initiative.

While the Risk Register provides risk insights for the mitigation initiatives, it does not provide risk insights for the assets within the service territory (i.e., circuits). To address this limitation, BVES developed the Fire Safety Circuit Matrix, which utilizes a qualitative risk methodology to assess risk at the circuit level. The circuit-level analysis considers the number of customers, wood poles, bare wire overhead circuit miles, tree attachments, and remaining expulsion fuses, which are then compiled and weighted to calculate the total risk score.

BVES uses the Fire Safety Circuit Matrix as a “living document” as mitigations are implemented. BVES re-evaluates the scores, incorporating any new mitigations, for Wildfire Risk Group, Priority, and Mitigation Weight at least every six months. Additionally, the Fire Safety Circuit Matrix is used to gauge progress and set 3-year targets for wildfire mitigation score reductions and associated wildfire ignition risk reduction.

5.1.1.2 In-process Conversion

BVES is in the process of transitioning to a live probabilistic risk model that will reflect the Draft Wildfire Mitigation Plan Guidelines (January 2025 edition). The first iteration of this quantitative model is the Phase 1 risk model. The Phase 1 risk model was developed by DIREXYON Solution (DIREXYON), who specializes in the development of asset management, risk management, and financial modeling solutions. Although the model has been populated with BVES data and has imported appropriate Technosylva results, it was not updated with current data or validated by SMEs in time for this submittal.

The BVES Phase 1 and Phase 2 risk model will address utility risk, comprised of two risk components: (1) wildfire risk, and (2) PSPS risk. Phase 3 will include Protective Equipment and Device Settings (PEDS) Risk.

The Phase 1 risk model utilizes the Technosylva Wildfire Analyst™ (WFA) product as a primary source of input data for the overall risk assessment. The WFA product includes three distinct applications as discussed below:

- **WFA FireRisk**: Daily asset-based risk forecasting to support operational needs, such as PSPS (previously called FireCast), including all situational awareness capabilities.

- **WFA FireSim**: On-demand wildfire spread modeling to support real-time incident analysis and "what if" analysis for pending weather events to support operational needs.
- **WFA FireSight**: Risk analysis for assets using historical fire scenarios to ensure comprehensive understanding of asset ignition probability and consequence to support mitigation planning, such as WMP prioritization and development. FireSight (previously called WRRM) includes integration of outage analytics, probability of outage/failure, and probability of ignition as well as built-in integrations to support calculations for risk reduction, mitigation effectiveness and risk spend efficiency.

The Phase 1 risk model evaluates three (3) distinct use cases to identify the appropriate wildfire mitigation strategy. The use cases are described below:

1. **GO 165 Minimum Requirements**: This use case analyzes meeting the minimum CPUC General Order 165 (GO 165) requirements regarding the Inspection Requirements for Electric Distribution and Transmission Facilities.
2. **Current BVES Strategy**: This use case reflects the current BVES strategy, which includes the following enhanced mitigation measures beyond the GO 165 minimum requirements:
    a. More frequent and extensive vegetation management.
    b. Installation of fire wraps on wood poles.
    c. Proactive replacement of conductors.
3. **Proactive Steel Pole Replacement**: This use case analyzes the alternative mitigation strategy of proactive replacement of wood poles with steel poles.

The Phase 2 risk model includes the following refinements to the Phase 1 risk model:

- Data refresh to reflect the current information,
- Inclusion of additional assets (i.e., arresters and connectors),
- Refinement of vegetation treatment (i.e., separate asset instead of included in the pole asset), and
- Refinement to the PSPS probability calculations.
- The PEDS risk is expected to be integrated into a future version (Phase 3) of the risk model.

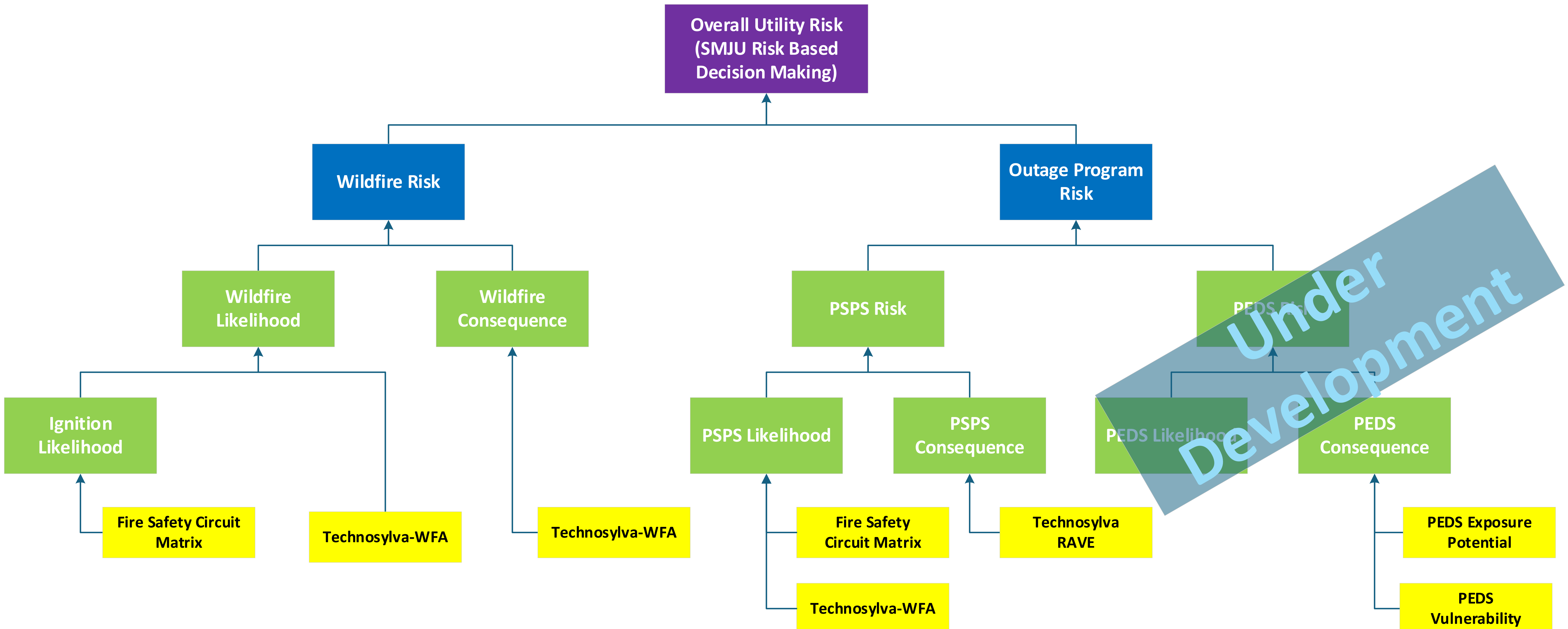
While BVES has not implemented the DIREXYON risk model yet, each iteration of the risk model aims to become more compliant with the guidance provided in the Draft Wildfire Mitigation Plan Guidelines (January 2025 edition). Once implemented, the risk model will enable BVES to make data-driven decisions aimed at reducing wildfire risk and minimizing exposure to outage risk events. See Appendix B for additional detail regarding the DIREXYON model.

5.2 Risk Analysis Framework

Figure 5-1 depicts the risk analysis framework.

The risk components are discussed in subsequent sections.

Figure 5-1 BVES Risk Analysis Framework



5.2.1 Risk and Risk Component Identification

The overall utility risk is comprised of the following 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 become a wildfire, and the potential consequences – considering hazard intensity, exposure potential, and vulnerability –for each community the wildfire reaches.
- **Outage Program 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.

The individual hazard risks are further broken down into 14 risk components. These risk components are split into two categories, intermediate and fundamental. Fundamental risk components are the inherent risk components that BVES must determine as part of its risk analysis. Intermediate risk components are the likelihood and consequence related to each hazard. Each fundamental or intermediate risk component provides valuable insight into BVES's wildfire and PSPS risk calculations.

There are five intermediate risk components:

1. **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 also includes the use of any method used to reduce the likelihood of ignition. For example, the use of protective equipment and device settings to reduce the likelihood of an ignition upon an initiating event.
2. **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 become a wildfire based on the probabilistic weather conditions in the area.
3. **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).

4. **PSPS likelihood** – The likelihood of an electrical corporation requiring a PSPS given a probabilistic set of environmental conditions.
5. **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).

There are nine fundamental risk components:

1. **Equipment ignition likelihood** – The likelihood that electrical corporation-owned equipment will cause an ignition either through normal operation or through failure.
2. **Contact from vegetation ignition likelihood** – The likelihood that vegetation will contact electrical corporation-owned equipment and result in an ignition.
3. **Contact by 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.
4. **Wildfire spread likelihood** – The likelihood that a fire with a nearby, but unknown, ignition point will become a wildfire and spread to a location in the service territory based on a probabilistic set of weather profiles, vegetation, and topography.
5. **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.
6. **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.
7. **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, SVI, age of structures, firefighting capacities).
8. **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.
9. **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).

BVES has adopted these definitions for its 2026 WMP and for future risk assessments. Figure 5-1 of this document depicts how the nine fundamental risk components are evaluated. Table 5-4 describes how these individual hazard risks, intermediate risk components and fundamental risk components are addressed in the current BVES model and the future end-state.

BVES is currently using two in-house tools (Fire Safety Circuit Matrix and Risk-Based Decision-Making Framework) as it has in the past that already incorporates most of the risk components listed above through SME evaluation.

The implementation of Technosylva's WFA-E and FireSight is complete. BVES contracted with DIREXYON in 2023 to utilize Technosylva data to model risk mitigation decision-making scenarios to maximize risk reduction efforts, and properly understand the short-term and long-term costs associated with the contemplated strategies. Phase 1 was completed in 2024, with Phase 2 scheduled for completion in 2025.

BVES will continue to develop its current models and add additional capability through Technosylva and DIREXYON products until the time BVES is fully able to holistically understand the dynamic ignition and PSPS risk facing BVES.

5.2.2 Risk and Risk Components Calculation

5.2.2.1 Likelihood of Risk Event

<u>Risk Mitigation Initiatives: Ignition Likelihood and PSPS Likelihood</u>

For risk mitigation initiatives, BVES utilizes the Risk Register Model which is a qualitative risk model that utilizes a logarithmic score matrix. The matrix considers likelihood and consequence as the two main input parameters. For likelihood, the values range between 1 ("occurs once every 100+ years") and 7 ("> 10 times per year") as noted in BVES Figure 5-2.

<u>Circuit-Level Risk: Ignition Likelihood</u>

The Fire Safety Circuit Matrix considers qualitative assessments of ignition likelihood as discussed in Section 5.2.2.3. Additionally, Technosylva's WFA-E model is used to inform the ignition likelihood.

<u>Circuit-Level Risk: PSPS Likelihood</u>

PSPS likelihood is not explicitly considered in the risk calculation as the PSPS risk is currently a consequence-based analysis.

Analysis Gaps

The following risk components are not specifically quantified in BVES's risk analysis methodology (gaps in BVES risk process), but are incorporated into the DIREXYON model.:

- Equipment-caused likelihood of ignition
- Contact from vegetation likelihood of ignition
- Contact from object likelihood of ignition
- Burn likelihood
- PSPS likelihood
- PEDS likelihood (Phase 3)

It should be noted that some of them are qualitatively evaluated in the Fire Safety Matrix, such as circuit performance, fault indicators and covered conductors, for the equipment-caused likelihood of ignition.

BVES is working with Technosylva and DIREXYON to address these gaps. As noted previously, the Phase 1 risk model has been completed but not implemented and Phase 2 is expected to be completed and implemented by the end of 2025. This transition from a qualitative framework to a quantitative framework will provide a long-term insight into these risk components. Through these efforts, BVES will be able to make data-driven decisions around mitigation efforts.

5.2.2.2 Consequence of Risk Event

Risk Mitigation Initiatives: Wildfire Consequence and PSPS Consequence

For risk mitigation initiatives, BVES utilizes the Risk Register Model which is a qualitative risk model that utilizes a logarithmic score matrix. The matrix considers likelihood and consequence as the two main input parameters. For consequence, the values range between 1 ("negligible") and 7 ("catastrophic") as noted in BVES Figure 5-2.

Circuit-Level Risk: Wildfire Consequence

Technosylva's WFA-E model (specifically FireSight) is used to obtain wildfire consequence.

Circuit-Level Risk: PSPS Consequence

To approximate the PSPS consequence (PSPS Exposure Potential and PSPS Vulnerability) the number of buildings that would be impacted by a PSPS and the fraction of the impacted population that has access and functional needs (AFN) and is thus expected to be more vulnerable to PSPS impacts was estimated. The AFN attributes considered are a proportion of the population that are seniors, experiencing poverty, and/or with a disability. These three AFN variables were consolidated into a single relative AFN vulnerability value for each circuit. The number of exposed buildings was also consolidated into a single value for each circuit. The AFN and building exposure values were then averaged into a single, relative PSPS exposure and vulnerability value for each circuit which ranges from 0-1. A value of 1 represents the highest observed value (most exposure /vulnerable) among the BVES circuits. A value of 0 represents no exposure or vulnerability (no buildings exposed and/or no vulnerable population).

Analysis Gaps

The following risk components are not specifically quantified in BVES's risk analysis methodology (gaps in BVES risk process), but are incorporated into the DIREXYON model.

- 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

BVES is working with Technosylva and DIREXYON to address these gaps. As noted previously, the Phase 1 risk model has been completed but not implemented and Phase 2 is expected to be completed and implemented by the end of 2025. This transition from a qualitative framework to a quantitative framework will provide a long-term insight into these risk components. Through these efforts, BVES will be able to make data-driven decisions around mitigation efforts.

5.2.2.3 Risk

Risk Mitigation Initiatives: Risk Register Model

For each risk mitigation initiative, wildfire risk and PSPS risk is calculated using the Risk Register in accordance with the safety model approach for Small and Multi-Jurisdictional Utilities (SMJU) provided in CPUC D.19-04-020 issued May 6, 2019.

The following intermediate risk components are determined by SME evaluation as inputs to the model:

- Wildfire likelihood
- Wildfire consequence
- PSPS likelihood
- PSPS consequence

BVES Figure 5-2 Risk Register Mode summarizes the 7x7 logarithmic risk score matrix that evaluates likelihood and consequence.

BVES Figure 5-2 Risk Register Mode (7x7 logarithmic risk score matrix)

Risk Score = Frequency * SUM i=1 to 5 (CategoryWeight i x 10^Impact i)													
Frequency	Frequency Years (Events/Year) [Min rate]	Frequency Years (Events/Year) [Max rate]	Frequency Value			Negligible(1)	Minor(2)	Moderate(3)	Major(4)	Extensive(5)	Severe(6)	Catastrophic(7)	
						1	2	3	4	5	6	7	
> 10 times per year	10	100	31.6228	7	0	316.23	3,162.28	31,622.78	316,227.77	3,162,277.66	31,622,776.60	316,227,766.02	7
1 - 10 times per year	1	10	3.1623	6	0	31.62	316.23	3,162.28	31,622.78	316,227.77	3,162,277.66	31,622,776.60	6
Once every 1 - 3 years	0.3300	1.0000	0.5745	5	0	5.74	57.45	574.46	5,744.56	57,445.63	574,456.26	5,744,562.65	5
Once every 3 - 10 years	0.1000	0.3333	0.1826	4	0	1.83	18.26	182.57	1,825.74	18,257.42	182,574.19	1,825,741.86	4
Once every 10 - 30 years	0.0333	0.1000	0.0577	3	0	0.58	5.77	57.74	577.35	5,773.50	57,735.03	577,350.27	3
Once every 30 - 100 years	0.0100	0.0333	0.0183	2	0	0.18	1.83	18.26	182.57	1,825.74	18,257.42	182,574.19	2
Once every 100+ Years	0.0033	0.0100	0.0058	1	0	0.06	0.58	5.77	57.74	577.35	5,773.50	57,735.03	1
				0	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
					0	1	2	3	4	5	6	7	

SME evaluations are performed for the likelihood and consequence assignments. The consequence risk component considers the following factors and weighting values based on SME feedback.

Reliability	Compliance	Quality of Service	Safety	Environmental
12.1%	17.1%	7.2%	60.5%	3.1%

Once likelihood and consequence are assigned values, risk (Wildfire and PSPS) is calculated using the following formula:

$$\text{Risk score} = \sum_{i=1}^{n} weight_i * frequency_i * 10^{impact_i}$$

The risk scores from the Risk Register Model are used to evaluate the effectiveness of the risk mitigation initiatives. For each risk mitigation initiative, the mitigated risk scores are compared against the baseline risk scores to determine the effectiveness of the mitigation initiative.

Fire Safety Circuit Matrix (Used for Circuit-Level Calculations)

The Fire Safety Circuit Matrix is a qualitative risk assessment tool that evaluates wildfire risk at the circuit level using qualitative risk scores across several risk factors. Additionally, the risk score considers several risk mitigation factors to reduce the risk score from the various risk factors.

The total risk score is calculated using the formula below:

$$Risk\ Score_{Circuit} = \sum_{1}^{10} Risk\ Score_{RiskFactor} - \sum_{1}^{9} Risk\ Score_{RiskMitigationFactor}$$

The table below summarizes the risk factors and risk scoring guide.

BVES Table 5-1 Fire Safety Circuit Matrix: Risk Factors

Fire Safety Circuit Matrix: Risk Factors	
Risk Factor	**Risk Scoring Guide**
Available Energy	This risk factor considers the voltage level of the circuit. Higher voltage circuits are generally riskier than lower voltage circuits. A risk score of 500 is assigned to 34.4kV circuits and a risk score of 50 is assigned to 4kV circuits.
High Fire Threat District (HFTD)	This risk factor considers the HFTD classification for the circuit. Higher tiers are generally riskier than lower tiers. The following equations are used: HFTD Tier 3: Risk = 10,000 * Bare Wire Circuit Miles HFTD Tier 2: Risk = 50 * Bare Wire Circuit Miles
Length of Overhead Bare Wire	This risk factor considers the length of overhead bare wire which can be a significant ignition source. A factor of 200 is applied to the length of bare wire circuit miles to estimate the risk score for this risk factor.

Fire Safety Circuit Matrix: Risk Factors	
Risk Factor	**Risk Scoring Guide**
Availability of Fuel	This risk factor considers the availability of fuel based on a qualitative assessment of vegetation density (i.e., high, medium, or low density). The following equations are used: High Density: Risk = 100 * Bare Wire Circuit Miles Medium Density: Risk = 25 * Bare Wire Circuit Miles Low Density: Risk = 5 * Bare Wire Circuit Miles
Susceptibility to High Winds	This risk factor considers susceptibility to high winds based on a qualitative assessment of wind intensity (i.e., high, medium, or low intensity). The following equations are used: High Intensity: Risk = 100 * Bare Wire Circuit Miles Medium Intensity: Risk = 25 * Bare Wire Circuit Miles Low Intensity: Risk = 5 * Bare Wire Circuit Miles
Number of Conventional Fuses	This risk factor considers the number of conventional fuses in the circuit. A factor of 2 is applied to the number of conventional fuses in the circuit.
Number of Tree Attachments	This risk factor considers the number of tree attachments. A factor of 4 is applied to the number of tree attachments.
Number of Uncorrected Level 1 Deficiencies	This risk factor considers the number of uncorrected Level 1 deficiencies. A factor of 1,000 is applied to the number of uncorrected Level 1 deficiencies.
Number of Uncorrected Level 2 Deficiencies	This risk factor considers the number of uncorrected Level 2 deficiencies. A factor of 100 is applied to the number of uncorrected Level 2 deficiencies.
Circuit Performance	This risk factor considers the top ten worst performing circuits, with the risk score decreasing by a value of 100 for each circuit (i.e., the 1st worst performing circuit has a risk score of 1,000 and the 10th worst performing circuit has a risk score of 100). All other circuits beyond the 10th worst performing circuit are assigned a risk score of zero for this risk factor.

The table below summarizes the risk mitigation factors and risk scoring guide.

BVES Table 5-2 Fire Safety Circuit Matrix: Risk Mitigation Factors

Fire Safety Circuit Matrix: Risk Mitigation Factors	
Risk Mitigation Factor	**Risk Scoring Guide**
Pole Loading Program (%Complete)	This risk mitigation factor considers the percent completion of the Pole Loading Program for the circuit. If the Pole Loading Program is not applicable, then a risk score of zero is used. The following equation is used: Risk Mitigation = (Number of Wood Poles) * (Percent Completion) * 5
Fault Indicator Program (%Complete)	This risk mitigation factor considers the percent completion of the Fault Indicator Program for the circuit. If the Fault Indicator Program is not applicable, then a risk score of zero is used. The following equation is used: Risk Mitigation = 100 * (Percent Completion) * 2
Enhanced Vegetation Management	This risk mitigation factor considers the progress made on the enhanced Vegetation Management program. The following equations are used: On Schedule (Green Status): Risk Mitigation = Bare Wire Circuit Miles * 2 Behind Schedule (Red Status): Risk Mitigation = 0
GO-165 Ground Patrol	This risk mitigation factor considers the use of GO-165 ground patrols. The following equations are used: In Periodicity (Green Status): Risk Mitigation = Bare Wire Circuit Miles * 2 Out of Periodicity (Red Status): Risk Mitigation = 0

Fire Safety Circuit Matrix: Risk Mitigation Factors	
Risk Mitigation Factor	**Risk Scoring Guide**
GO-165 5-Year Inspections	This risk mitigation factor considers the use of GO-165 5-year inspections. The following equations are used: In Periodicity (Green Status): Risk Mitigation = Bare Wire Circuit Miles * 2 Out of Periodicity (Red Status): Risk Mitigation = 0
GO-165 Intrusive Inspections	This risk mitigation factor considers the use of GO-165 intrusive inspections. The following equations are used: In Periodicity (Green Status): Risk Mitigation = Bare Wire Circuit Miles * 2 Out of Periodicity (Red Status): Risk Mitigation = 0
Bi-Annual LiDAR Survey	This risk mitigation factor considers the use of bi-annual LiDAR surveys. The following equations are used: In Periodicity (Green Status): Risk Mitigation = Number of Wood Poles * 2 Out of Periodicity (Red Status): Risk Mitigation = 0
3rd Party Annual Ground Patrol	This risk mitigation factor considers the use of 3rd party annual ground patrol. The following equations are used: In Periodicity (Green Status): Risk Mitigation = Bare Wire Circuit Miles * 2 Out of Periodicity (Red Status): Risk Mitigation = 0
GO-174 Substation Inspections	This risk mitigation factor considers the use of GO-174 substation inspections. The following equations are used: In Periodicity (Green Status): Risk Mitigation = Bare Wire Circuit Miles * 2 Out of Periodicity (Red Status): Risk Mitigation = 0

FireSight (Used for Circuit-Level Calculations)

In addition to the qualitative Fire Safety Circuit Matrix, a quantitative risk analysis is performed using the FireSight module of WFA-E. FireSight calculates the 98th percentile acres burned risk score by segment and those results are rolled up to the circuit level. The 98th percentile acres burned risk scores are categorized into risk score bins and a weighted risk score calculation is performed using the circuit miles length associated with each risk score bin.

Normalization of Risk (Used for Circuit-Level Calculations)

Once the Fire Safety Circuit Matrix and FireSight risk scores are calculated for each circuit, the risk scores are normalized to get both sets of risk scores on the same scale. The ratio between the circuit-level risk score and the maximum circuit-level risk score represents the normalized risk score. The normalized risk scores are reported in Section 5.5.

Analysis Gaps

The following risk components are not utilized in BVES's risk analysis methodology (gaps in BVES risk process). PSPS portion of Outage Risk will be incorporated into the DIREXYON Phase 2 model and PEDS will be incorporated into the DIREXYON Phase 3 model:

- PSPS risk
- PEDS risk

BVES is working with Technosylva and DIREXYON to address these gaps. As noted previously, the Phase 1 risk model has been completed but not implemented and Phase 2 is expected to be completed and implemented by the end of 2025. This transition from a qualitative framework to a quantitative framework will provide a long-term insight into these risk components. Through these efforts, BVES will be able to make data-driven decisions around mitigation efforts.

5.2.3 Key Assumptions and Limitations

Table 5-1 Risk Modeling Assumptions and Limitations summarizes the key modeling assumptions and limitations for the risk methodology.

BVES will continue to regularly monitor and evaluate the scope and validity of modeling assumptions related to the following categories:

- 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 / wind adjustment factor calculation.
- General equipment failure rates / wind speed functional dependence for unknown components.
- General vegetation contact rates / wind speed functional dependence for unknown species.
- Height of electrical equipment in the service territory.
- Stability of the atmosphere and resulting calculation of near-surface winds.
- Vegetative fuels and fuel models including adaptations based on fuel management activities by other Public Safety Partners.
- Combination of risk components / weighting of attributes in alignment with most recent decision issued by the CPUC for inclusion in RAMP filings.
- Wind load capacity for electrical equipment in the service territory.
- Number, extent, and type of community assets at risk in the service territory.
- Proxies for estimating impact on customers and communities in the service territory.
- Extent, distribution, and characteristics of vulnerable populations in the service territory.

Table 5-1 Risk Modeling Assumptions and Limitations

Assumption	Justification	Limitation	Applicable Models
The model evaluates each mitigation measure in isolation of other mitigation measures to calculate risk benefit.	N/A	N/A	Risk Register Model
Currently BVES utilizes SME evaluation of likelihood and consequence instead of raw data input. SME's evaluate data sources such as outage log, LiDAR surveys, asset hardening, etc. in developing their evaluations. While the data is largely standardized and consistent, the input to the model from the data can fluctuate somewhat due to the inherent subjectivity of the SME's interpretation of the data.	N/A	N/A	Risk Register Model
Because the determination of likelihood and consequence is by SME evaluation, stability of the assumptions is susceptible to instability when SMEs change.	N/A	N/A	Risk Register Model
The physical framework development is based on an idealized situation in steady state spread which may not fit some extreme behavior of fires.	N/A	N/A	WFA-E

Fuels are assumed to be continuous and uniform for the scale of the input (typically between 10-to-30-meter (m) resolution).	N/A	N/A	WFA-E
Fire characteristics at a point only depends on the conditions at that point (point-functional model). This means that there are certain non-local phenomena like: · Increase of ROS due to a concave front. · Fire interaction between different parts of the same fire or a different one.	N/A	N/A	WFA-E
Fire spread is assumed to be elliptical although there are several variations such as double ellipse, oval, egg-shape, etc.	N/A	N/A	WFA-E
Weather is given hourly and is assumed to remain constant during that time. There is no interpolation in time to compute evolution of weather between hours.	N/A	N/A	WFA-E
Reliability of weather inputs in the mid-range forecast (2 to 5 days).	N/A	N/A	WFA-E
Fire is not coupled with the atmosphere in any way. This may seem like a major limitation in the model as wind is a main contribution to fire spread and at present many models (especially physical ones) try to couple wind and fire. The main reasons for us not to consider the coupling is: · It would make it unfeasible to run millions of simulations considering the coupling effect. · Empirical and semi-empirical models have been developed using an average wind speed as an input, so it is not clear that considering more granular wind at the front is advisable.	N/A	N/A	WFA-E
Fire is always assumed to be fully developed. Fire acceleration, flashover, or decay is not considered.	N/A	N/A	WFA-E
Atmospheric instability which may have a deep impact on ROS (beer 1991) is not considered in the model.	N/A	N/A	WFA-E
Gusts are not considered in the model.	N/A	N/A	WFA-E
No interaction between slope and wind other than creating an effective or equivalent wind. This means that fire is assumed to have an elliptical shape no matter the alignment of wind and slope.	N/A	N/A	WFA-E
Models have been developed with scares empirical data. The abundance of today's fire data sources, however, is allowing us to better adjust models to observed fire patterns.	N/A	N/A	WFA-E
Fuel array description of the vegetation may not perfectly describe fuel characteristics.	N/A	N/A	WFA-E
Spotting is only considered in surface fires.	N/A	N/A	WFA-E

5.3 Risk Scenarios

BVES's risk models consider reasonable design basis and extreme-event scenarios for wildfire and outage risk events. With the implementation of the Technosylva WFA models and the incorporation of these models into DIREXYON's models, BVES will be able to conduct long-term risk mitigation planning and review the overall risk levels for the utility on a pre-mitigation, post-mitigation, and mitigation decision basis.

5.3.1 Design Basis Scenarios

BVES utilizes a design scenario that most closely reflects Wind Loading Condition 1, Wind Loading Condition 2, Weather Condition 2, Vegetation Condition 1, and Vegetation Condition 3 for mitigation planning purposes in its risk frameworks.

Technosylva's WFA FireSight analysis uses a subset of historical weather data to simulate wildfires on specific days, considering ignition points along utility assets. The resulting risk scores are then combined to provide a comprehensive assessment of the distribution of wildfire risk. The selection of weather days to simulate is based on a careful consideration of both typical and extreme conditions throughout the historical weather data, ensuring that the resulting risk distribution accurately reflects the full range of potential scenarios. Every year, the FireSight analysis is performed using the latest available weather data to ensure its relevance for the upcoming WMP cycles, thus maintaining its accuracy and effectiveness over time. For the current year analysis, Technosylva used a total of 179 historic weather days to simulate wildfires. Wind speed and dead fuel moisture conditions are calculated for each circuit.

For wind loading on electrical equipment, BVES considers at least four statistically relevant design conditions. Wind loading is calculated based on locally relevant 3-second wind gusts over a 30-year wind speed history during fire season in its service territory. The four conditions are:

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

For weather conditions used in calculating fire behavior, BVES uses probabilistic scenarios based on a 30-year history of fire weather. This approach considers a range of wind speeds, directions, and fuel moistures that are representative of historic conditions in the BVES service area. With these historic data as inputs, BVES considers 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 30-year history.

Technosylva's analysis for BVES currently uses the SDG&E definitions of "fire weather" and "fire season," but is working to update these definitions to be more specific to BVES's service area in future WMP updates.

For vegetative conditions not including short-term moisture content, BVES evaluates design scenarios including the current and forecasted vegetative type and coverage. The conditions BVES considers include the following:

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

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

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

Table 5-2 Summary of Design Basis Scenarios

Scenario ID	Design Scenario	Purpose
WL1	Wind Load Condition 1	Used in the WFA FireSight models.
WL2	Wind Load Condition 2	
WC2	Weather Condition 2,	
VC1	Vegetation Condition 1	
VC3	Vegetation Condition 3	

5.3.2 Extreme-Event Scenarios/Uncertainty Scenarios

BVES currently utilizes a long-term extreme-event scenario developed in coordination with Technosylva (summarized in **Error! Reference source not found.**). BVES believes modeling the risk in 2030 is appropriate for ensuring grid hardening efforts that are effective for reduction of both wildfire and outage risks.

The incorporation of modeled 2030 climate conditions into BVES's analysis is a new capability in the 2026 WMP. BVES will continue to monitor developments in this area to determine whether the approach is reasonable and prudent for a utility with the size and risk profile of Bear Valley or should be adjusted in future analyses.

Now that climate change impacts have been incorporated, BVES plans to consider the following extreme-event scenarios in future WMP updates:

- 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)

Table 5-3 Summary of Extreme-Event Scenarios

Scenario ID	Extreme-Event Scenario	Purpose
ES1	2030 Climate Conditions (mostly concerned with fuel levels and moisture)	Assess if climate change, as well as any resulting changes in wildfire consequence, may influence BVES's existing grid hardening strategy.

5.4 Summary of Risk Models

Table 5-4 summarizes the calculation approach for each risk metric and risk component utilized in the overall risk assessment.

Table 5-4 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	Wind Load Condition 1, Wind Load Condition 2, Weather Condition 2, Vegetation Condition 1, Vegetation Condition 3	Wildfire Risk (R2) Outage Program Risk (R3)	Current: BVES Risk Register Model, Fire Safety Circuit Matrix, and Technosylva WFA Future: DIREXYON and Technosylva WFA	Overall utility risk at the circuit or at the risk mitigation initiative.	Unitless
R2	Wildfire Risk	Wind Load Condition 3, Weather Condition 2, Vegetation Condition 1, Vegetation Condition 3	Wildfire Likelihood (IRC1) Wildfire Consequence (IRC3)	Current: BVES Risk Register Model, Fire Safety Circuit Matrix, and Technosylva WFA Future: DIREXYON and Technosylva WFA	Wildfire risk at the circuit or at the risk mitigation initiative.	Unitless
R3	Outage Program Risk	Wind Load Condition 2, Weather Condition 1, Vegetation Condition 1	PSPS Likelihood (IRC4) PSPS Consequence (IRC5) PEDS Outage Likelihood (IRC6) [Deferred to a future update] PEDS Outage Consequence (IRC7) [Deferred to a future update]	Current: BVES Risk Register Model, Fire Safety Circuit Matrix, Technosylva WFA, and Technosylva RAVE Future: DIREXYON, Technosylva WFA, and Technosylva RAVE	Outage program risk at the circuit or at the risk mitigation initiative.	Unitless
R4	PSPS Risk	Wind Load Condition 2, Weather Condition 1, Vegetation Condition 1	PSPS Likelihood (IRC4) PSPS Consequence (IRC5)	Current: BVES Risk Register Model, Fire Safety Circuit Matrix, Technosylva WFA, and Technosylva RAVE Future: DIREXYON, Technosylva WFA, and Technosylva RAVE	PSPS risk at the circuit level or at the risk mitigation initiative level.	Unitless
R5	PEDS Outage Risk	NA - Deferred to a future update.	NA - Deferred to a future update.	NA - Deferred to a future update.	NA - Deferred to a future update.	NA - Deferred to a future update.
IRC1	Wildfire Likelihood	Wind Load Condition 3, Weather Condition 2, Vegetation Condition 1, Vegetation Condition 3	Burn Likelihood (FRC4) Ignition Likelihood (IRC2)	Current: BVES Risk Register Model, Fire Safety Circuit Matrix, and Technosylva WFA Future: DIREXYON and Technosylva WFA	Wildfire Likelihood per circuit.	Unitless
IRC2	Ignition Likelihood	Wind Load Condition 3, Weather Condition 2, Vegetation Condition 1, Vegetation Condition 3	Equipment Caused Ignition Likelihood (FRC1) Contact from Vegetation Ignition Likelihood (FRC2) Contact from Object Ignition Likelihood (FRC3)	Current: Fire Safety Circuit Matrix and Technosylva WFA Future: DIREXYON and Technosylva WFA	Ignition Likelihood per circuit.	Unitless
IRC3	Wildfire Consequence	Wind Load Condition 3, Weather Condition 2, Vegetation Condition 1, Vegetation Condition 3	Wildfire Hazard Intensity (FRC5) Wildfire Exposure Potential (FRC6)	Current: Technosylva WFA Future: DIREXYON and Technosylva WFA	Wildfire Consequence per circuit.	Unitless

			Wildfire Vulnerability (FRC7)			
IRC4	PSPS Likelihood	Wind Load Condition 2, Weather Condition 1, Vegetation Condition 1	Wildfire Likelihood (IRC1)	Current: Technosylva WFA Future: DIREXYON and Technosylva WFA	PSPS Likelihood per circuit.	Unitless
IRC5	PSPS Consequence	Wind Load Condition 2, Weather Condition 1, Vegetation Condition 1	Wildfire Exposure Potential (FRC6) Wildfire Vulnerability (FRC7) PSPS Exposure Potential (FRC8) PSPS Vulnerability (FRC9)	Current: Technosylva RAVE Future: DIREXYON, Technosylva WFA, and Technosylva RAVE	AFN customers and buildings impacted per circuit level	Customers per circuit Buildings per circuit
IRC6	PEDS Outage Likelihood	NA - Deferred to a future update.	NA - Deferred to a future update.	NA - Deferred to a future update.	NA - Deferred to a future update.	NA - Deferred to a future update.
IRC7	PEDS Outage Consequence	NA - Deferred to a future update.	NA - Deferred to a future update.	NA - Deferred to a future update.	NA - Deferred to a future update.	NA - Deferred to a future update.
FRC1	Equipment Caused Ignition Likelihood	Wind Load Condition 2, Weather Condition 1, Vegetation Condition 1	Distribution Asset Data, Historical Outages and Ignitions	Current: None Future: DIREXYON	Likelihood of ignition caused by equipment at the asset level.	Annualized ignition probability of ignition
FRC2	Contact from Vegetation Ignition Likelihood	Wind Load Condition 2, Weather Condition 1, Vegetation Condition 1	Distribution Asset Data, Historical Outages and Ignitions	Current: None Future: DIREXYON	Likelihood of ignition from vegetation contact at the asset level.	Annualized ignition probability of ignition
FRC3	Contact from Object Ignition Likelihood	Wind Load Condition 2, Weather Condition 1, Vegetation Condition 1	Distribution Asset Data, Historical Outages and Ignitions	Current: None Future: DIREXYON	Likelihood of ignition from object contact at the asset level.	Annualized ignition probability of ignition
FRC4	Burn Likelihood	Wind Load Condition 3, Weather Condition 1, Vegetation Condition 1, Vegetation Condition 3	Vegetation	Current: Technosylva WFA Future: DIREXYON and Technosylva WFA	100m x 100m pixel destructive potential classification	Unitless
FRC5	Wildfire Hazard Intensity	Wind Load Condition 3, Weather Condition 1, Vegetation Condition 1, Vegetation Condition 3	Sustained Wind Speeds Vegetation	Current: Technosylva WFA Future: DIREXYON and Technosylva WFA	100m x 100m pixel destructive potential classification	Unitless

FRC6	Wildfire Exposure Potential	Wind Load Condition 3, Weather Condition 1, Vegetation Condition 1, Vegetation Condition 3	Topography	Current: Technosylva WFA Future: DIREXYON and Technosylva WFA	100m x 100m pixel destructive potential classification	Unitless
FRC7	Wildfire Vulnerability	Wind Load Condition 3, Weather Condition 1, Vegetation Condition 1, Vegetation Condition 3	Customer demographics and AFN population	Current: Technosylva WFA and Technosylva RAVE Future: DIREXYON, Technosylva WFA, and Technosylva RAVE	AFN population per circuit	Customers per circuit
FRC8	PSPS Exposure Likelihood	Wind Load Condition 3, Weather Condition 1, Vegetation Condition 1, Vegetation Condition 3	Customer demographics, AFN population, and building locations	Current: Technosylva RAVE Future: DIREXYON, Technosylva WFA, and Technosylva RAVE	AFN customers and buildings impacted per circuit level	Customers per circuit Buildings per circuit
FRC9	Vulnerability of Community to PSPS (PSPS Vulnerability)	Wind Load Condition 3, Weather Condition 1, Vegetation Condition 1, Vegetation Condition 3	Customer demographics, AFN population, and building locations	Current: Technosylva RAVE Future: DIREXYON, Technosylva WFA, and Technosylva RAVE	AFN customers and buildings impacted per circuit level	Customers per circuit Buildings per circuit
FRC10	PEDS Outage Exposure Likelihood	NA - Deferred to a future update.	NA - Deferred to a future update.	NA - Deferred to a future update.	NA - Deferred to a future update.	NA - Deferred to a future update.
FRC11	PEDS Outage Vulnerability	NA - Deferred to a future update.	NA - Deferred to a future update.	NA - Deferred to a future update.	NA - Deferred to a future update.	NA - Deferred to a future update.

5.5 Risk Analysis Results and Presentation

5.5.1 Top Risk Areas within the HFRA

BVES is primarily in HFTD Tier 2, with a small portion in HFTD Tier 3 along the Radford Line. BVES does not have any self-identified HFRAs that are outside or deemed at higher risk than the CPUC's HFTD designations. BVES will continue to assess if the HFRA areas need to be identified or HFTD boundaries need adjustment in 2026 and beyond.

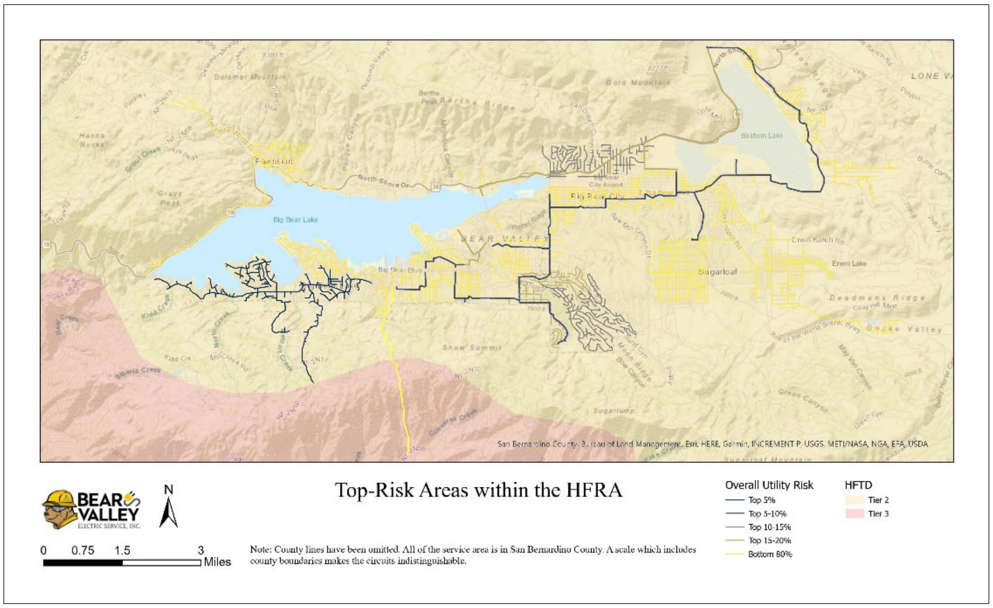
BVES determines overall utility risk at the circuit level via the Fire Safety Circuit Matrix and the Technosylva FireSight module and the PSPS consequence surrogate discussed in Section 5.2.2.2. The risk models evaluate all BVES circuits and BVES orders the circuits by overall risk which includes both wildfire risk and PSPS risk. The overall risk values include the risk reductions from the mitigation efforts BVES has undertaken to reduce those risks as of December 31, 2024.

5.5.1.1 Geospatial Maps of Top-Risk Areas within the HFRA

BVES determines overall utility risk at the circuit level via the Fire Safety Circuit Matrix and the Technosylva FireSight module. The risk models evaluate all BVES circuits and BVES orders the circuits by overall risk which includes both wildfire risk and PSPS risk. The overall risk values include the risk reductions from the mitigation efforts BVES has undertaken to reduce those risks.

Figure 5-3 shows each circuit's risk level as well as HFTD tiers. All of BVES is in San Bernadino so county lines are not included.

BVES Figure 5-3 Top Risk Areas HFRA



5.5.1.2 Proposed Updates to the HFTD

Currently, BVES does not see a need for any changes to the HFTD designations for the Bear Valley service territory of which nearly all the territory is Tier 2 with a small area of Tier 3 along the Radford Line. BVES already identifies and maps its highest risk areas through the Technosylva products, the CPUC and Cal Fire maps, and the Fire Safety Circuit Matrix. If conditions change, due to changes in land use, vegetation density, or climatological factors, BVES will propose such changes to the Commission.

5.5.2 Top Risk-Contributing Circuits/Segments/Spans

BVES identifies and maps all circuits in the Fire Safety Circuit Matrix. The output of this effort is shown below in Table 5-5. BVES further describes the Fire Safety Circuit Matrix, including its data inputs in Section 5.1.1. In addition to the Fire Safety Circuit Matrix, BVES uses Technosylva’s FireSight and RAVE models to incorporate qualitative insights on wildfire consequences and PSPS exposure potential and vulnerability.

Table 5-5 Summary of Top-Risk Circuits, Segments, or Spans

Risk Ranking	Circuit	Overall Utility Risk Score	Wildfire Risk Score	Outage Program Risk Score	Top Risk Contributors	Total Miles	Version of Risk Model Used
1	Boulder	0.59	0.66	0.51	Overhead Bare Wire Length	17.5	Fire Safety Circuit Matrix
2	Shay	0.56	0.24	0.88	None	17.3	Fire Safety Circuit Matrix
3	Holcomb	0.52	0.55	0.49	Overhead Bare Wire Length	13.3	Fire Safety Circuit Matrix
4	Goldmine	0.51	0.49	0.54	Overhead Bare Wire Length	13.2	Fire Safety Circuit Matrix
5	Clubview	0.48	0.41	0.55	Overhead Bare Wire Length	10.2	Fire Safety Circuit Matrix
6	Baldwin	0.48	0.53	0.42	Overhead Bare Wire Length	8.3	Fire Safety Circuit Matrix
7	North Shore	0.47	0.63	0.31	Overhead Bare Wire Length	15.7	Fire Safety Circuit Matrix
8	Pioneer	0.44	0.62	0.26	Overhead Bare Wire Length	16.4	Fire Safety Circuit Matrix
9	Sunrise	0.36	0.14	0.58	Overhead Bare Wire Length	7.6	Fire Safety Circuit Matrix
10	Radford	0.36	0.44	0.28	Overhead Bare Wire Length	3.1	Fire Safety Circuit Matrix
11	Erwin Lake	0.36	0.10	0.62	None	21.9	Fire Safety Circuit Matrix
12	Eagle	0.35	0.14	0.57	Overhead Bare Wire Length	6.6	Fire Safety Circuit Matrix
13	Sunset	0.34	0.19	0.48	Overhead Bare Wire Length	10.3	Fire Safety Circuit Matrix
14	Interlacken	0.33	0.09	0.57	Overhead Bare Wire Length	5.5	Fire Safety Circuit Matrix
15	Castle Glen	0.32	0.13	0.52	Overhead Bare Wire Length	6.9	Fire Safety Circuit Matrix
16	Garstin	0.32	0.09	0.55	Overhead Bare Wire Length	5.3	Fire Safety Circuit Matrix
17	Paradise	0.30	0.14	0.47	Overhead Bare Wire Length	9.8	Fire Safety Circuit Matrix
18	Country Club	0.29	0.14	0.44	Overhead Bare Wire Length	3.2	Fire Safety Circuit Matrix
19	Georgia	0.28	0.07	0.48	Overhead Bare Wire Length	4.8	Fire Safety Circuit Matrix
20	Lagonita	0.28	0.16	0.39	Overhead Bare Wire Length	6.7	Fire Safety Circuit Matrix
21	Pump House	0.26	0.03	0.48	Overhead Bare Wire Length	0.6	Fire Safety Circuit Matrix
22	Harnish	0.23	0.10	0.35	Overhead Bare Wire Length	1.5	Fire Safety Circuit Matrix
23	Lift	0.03	0.06	0.00	Overhead Bare Wire Length	0.0	Fire Safety Circuit Matrix

5.6 Quality Assurance and Quality Control

BVES has utilized third parties such as Technosylva and DIREXYON to review and process its data as it pertains to risk. Both firms use open, peer reviewed data sets, along with BVES data, to develop their models. BVES will continue to explore methods to improve its data gathering, QA/QC processes, and independent review of its data, models, and assumptions.

Internally, the data for BVES's Risk-Based Decision-Making Framework and Fire Safety Circuit Matrix utilize internal data gathered from BVES staff and contractors across the service territory as well as data BVES gathers from the CPUC, other utilities, the US Census Bureau, the National Weather Service, and more. BVES seeks data from these reliable sources and takes pains to ensure the data is accurate, timely, and fit for the purpose to which it is applied.

Technosylva uses the following independent review results (Guide ASTM E 1355) described below:

- The core models implemented in WFA-E form the basis of most operational propagation models in use today (Andrews et al 1980, Gould 1991). They have been implemented in well-known software like NEXUS (Scott and Reinhardt 2001), Fire and Fuels Extension to Forest Vegetation Simulator (FFE-FVS) (Reinhardt and Crookston 2003), FARSITE (Finney 2004), Fuel Management Analyst (FMAPlus) (Carlton2005), FlamMap (Finney 2006) and BehavePlus (Andrews et al.2008). Nevertheless, forest fires are a very difficult phenomenon to simulate that depends on many different factors, therefore typical simulations can predict the source dataset with mean absolute percent errors between 20 and 40% (Cruz et al. 2013).
- One important factor in fire simulation is the definition of the fuel models, with analysis providing different results for different fuels and regions. For example, Sanders (2001) observed a pattern of over-prediction by FARSITE in fuel models 1,2,5 by a large margin, moderate in fuel 10 and some underprediction for fuel model 8. Zigner et al (2020) used two case studies during strong winds revealing that FARSITE was able to successfully reconstruct the spread rate and size of wildfires when spotting was minimal. However, in situations when spotting was an important factor in rapid downslope wildfire spread, both FARSITE and FlamMap were unable to simulate realistic fire perimeters. Ross et al. (2006) used measurements from temperature sensors during prescribed burn in the Appalachian Mountains to recreate the fires and compared fire behavior simulated by FARSITE. They obtain a set of ROS adjustment factors that better represented the observed fire behavior obtaining a ROS adjustment factor of 1.5 and 2 for fuels 9 and 11 respectively, and a decreasing factor of 0.2 to the fuel type 6.

- Apart from these reviews, Technosylva has been constantly improving the accuracy and performance of the published fire models to better adjust the results to observed fire behavior. This includes a better definition of the fuel types, improved forecast of live fuel moisture content, modifications to the crown fire modeling initialization scheme, and automatic fire adjustment based on data assimilation techniques using ROS adjustment factor. In addition, Technosylva has implemented more than 21 additional models into the WFA-E platform to enhance accuracy and address known limitations of published fire models. These improvements include crown fire analysis, ember and spotting, urban / non-burnable area encroachment, consequence and impact quantification, etc. It is important to note that improvement of the fire modeling platform of choice necessitates not only improvements in mathematical algorithms but substantial improvements in the accuracy and resolution of input data sources. These improvements work in concert to enhance the modeling and outputs to match observed and expected fire behavior. A robust operationalization of fire models requires constant and ongoing research, testing, validation and implementation of both models and data sources.

With more reliance on the integration of Technosylva and DIREXYON software tools and data sources integration with BVES data sets, a risk assessment improvement activity has been added to establish a process and protocol for 1) sharing of data, 2) validating that data used is correct, 3) establishing a data schema such that the correct 'source of truth' is used, and finally setting up a periodicity for data updates such that the data is received in timely manner.

5.6.1 Independent Review

BVES has utilized third parties such as Technosylva and DIREXYON to review and process its data as it pertains to risk. Both firms use open, peer reviewed data sets, along with BVES data, to develop their models. BVES will continue to explore methods to improve its data gathering, QA/QC processes, and independent review of its data, models, and assumptions.

Internally, the data for BVES's Risk-Based Decision-Making Framework and Fire Safety Circuit Matrix utilize internal data gathered from BVES staff and contractors across the service territory as well as data BVES gathers from the CPUC, other utilities, the US Census Bureau, the National Weather Service, and more. BVES seeks data from these reliable sources and takes pains to ensure the data is accurate, timely, and fit for the purpose to which it is applied.

Technosylva uses the following the independent review results (Guide ASTM E 1355) described below:

- The core models implemented in WFA-E form the basis of most operational propagation models in use today (Andrews et al 1980, Gould 1991). They have been implemented in well-known software like NEXUS (Scott and Reinhardt 2001), Fire and Fuels Extension to Forest Vegetation Simulator (FFE-FVS) (Reinhardt and Crookston 2003), FARSITE (Finney 2004), Fuel Management Analyst (FMAPlus) (Carlton2005), FlamMap (Finney 2006) and BehavePlus (Andrews et al.2008). Nevertheless, forest fires are a very difficult phenomenon to simulate that depends on many different factors, therefore typical simulations can predict the source dataset with mean absolute percent errors between 20 and 40% (Cruz et al. 2013).
- One important factor in fire simulation is the definition of the fuel models, with analysis providing different results for different fuels and regions. For example, Sanders (2001) observed a pattern of over-prediction by FARSITE in fuel models 1,2,5 by a large margin, moderate in fuel 10 and some underprediction for fuel model 8. Zigner et al (2020) used two case studies during strong winds reveling that FARSITE was able to successfully reconstruct the spread rate and size of wildfires when spotting was minimal. However, in situations when spotting was an important factor in rapid downslope wildfire spread, both FARSITE and FlamMap were unable to simulate realistic fire perimeters. Ross et al. (2006) used measurements from temperature sensors during prescribed burn in the Appalachian Mountains to recreate the fires and compared fire behavior simulated by FARSITE. They obtain a set of ROS adjustment factors that better represented the observed fire behavior obtaining a ROS adjustment factor of 1.5 and 2 for fuels 9 and 11 respectively, and a decreasing factor of 0.2 to the fuel type 6.
- Apart from these reviews, Technosylva has been constantly improving the accuracy and performance of the published fire models to better adjust the results to observed fire behavior. This includes a better definition of the fuel types, improved forecast of live fuel moisture content, modifications to the crown fire modeling initialization scheme, and automatic fire adjustment based on data assimilation techniques using ROS adjustment factor. In addition, Technosylva has implemented more than 21 additional models into the WFA-E platform to enhance accuracy and address know limitations of published fire models. These improvements include crown fire analysis, ember and spotting, urban / non-burnable area encroachment, consequence and impact quantification, etc. It is important to note that improvement of the fire modeling platform of choice necessitates not only improvements in mathematical algorithms but substantial improvements in the accuracy and resolution of input data sources. These improvements work in concert to enhance the modeling and outputs to match observed and expected fire behavior. A robust operationalization of fire models requires constant and ongoing research, testing, validation and implementation of both models and data sources.

With more reliance on the integration of Technosylva and DIREXYON software tools and data sources integration with BVES data sets, a risk assessment improvement activity has been added to establish a process and protocol for 1) sharing of data, 2) validating that data used is correct, 3) establishing a data schema such that the correct ‘source of truth’ is used, and finally setting up a periodicity for data updates such that the data is received in timely manner.

5.6.2 Model Controls, Design, and Review

Per the engagement agreement, and the description above in Section 5.6.1, BVES relies upon Technosylva for this type of analysis. Technosylva maintains that it meets all the requirements set forth by Energy Safety in this section.

As stated in Section 5.6.1, with more reliance on the integration of Technosylva and DIREXYON software tools. A risk assessment improvement activity has been added to establish a process for the procurement (e.g., ensuring appropriate V&V) and use of software (version control, etc).

5.7 Risk Assessment Improvement Plan

BVES has made significant advancements in its risk modeling capabilities to optimize the identification of areas of highest wildfire risk and PSPS vulnerability. These efforts have helped BVES better inform its selection of wildfire mitigation initiatives and prioritization of grid hardening and inspections. In the past four years, BVES progressively implemented probabilistic risk modeling capabilities.

- In 2020, BVES engaged REAX Engineering to develop full field-effect wildfire probability and consequence maps for 2021 and 2050.
- In 2022, BVES implemented Technosylva’s Wildfire Analyst Enterprise (WFA-E) model.
- In 2023, BVES implemented Technosylva’s FireSight (formerly Wildfire Risk Reduction Model (WRRM)) model.
- In 2024, BVES implemented a Fire Potential Index (FPI) calculation developed by Technosylva.
- In 2024, BVES engaged Direxyon to develop a utility risk model that evaluates ignition risk and PSPS risk by drawing inputs from the Technosylva models, Bear Valley’s asset databases, inspection results, and customer information system. The Direxyon model will also help BVES to evaluate cost in relation to risk reduction as well as evaluate alternate mitigation strategies, helping optimize

long term strategic planning to reduce wildfire risk. Additional status on the DIREXYON model conversion is provided in Appendix B.

The following improvements are planned for the Direxyon model:

- Data refresh to reflect the current information,
- Inclusion of additional assets (i.e., arresters and connectors),
- Refinement of vegetation treatment (i.e., separate asset instead of included in the pole asset), and
- Refinement to the PSPS probability calculations.

The PEDS risk is expected to be integrated into a future version of the risk model.

While BVES has not implemented the DIREXYON risk model yet, each iteration of the risk model aims to become more compliant with the guidance provided in the Draft Wildfire Mitigation Plan Guidelines (February 2025 edition). The following narrative provides *a summary* of the proposed improvement plan included in **Table 5-6 Utility Risk Assessment Improvement Plan.**

5.7.1 RA-1-A. Complete Integration of Direxyon and Technosylva Models

- **Problem statement** – BVES has begun the integration of the Direxyon software suite with the Technosylva WFA-E models.
- **Planned Improvement** – BVES intends to develop and implement a comprehensive risk enterprise system. BVES will also develop and implement processes for control and use of the system and a training program for staff to promote utilization and optimization of the system.
- **Anticipated Benefit** – BVES anticipates the benefit to adopting a comprehensive enterprise risk tool is to produce reliable quantitatively derived wildfire risk, ignition risk, PSPS risk and overall utility risk and display it in a manner that is useful to decision makers. This will also help BVES better identify, understand, quantify, and evaluate inherent, emerging, intermediate, and residual risks across its system and to the utility in a manner that is digestible for management. Clear presentation of risks allows the management, staff, and stakeholders to manage risks in a manner that maximizes public safety, reliability, operational efficiency on a cost-effective basis through careful planning organized implementation of risk reduction efforts.
- **Region prioritization (where relevant)** – BVES will analyze its entire service territory through this initiative.

5.7.2 RA-1-B. Develop verification and validation documentation for ignition models.

- **Problem statement** – All assets (i.e, arresters and connectors), a more refined vegetation treatment (i.e., separate asset instead of included in the pole asset), and PSPS treatment is necessary.
- **Planned Improvement** – Inclusion of additional assets (i.e., arresters and connectors), refinement of vegetation treatment (i.e., separate asset instead of included in the pole asset), and refinement to the PSPS probability
- **Anticipated Benefit** – BVES anticipates the benefit to be the ability to have more granularity on each asset and risk component for more refined decision making .
- **Region prioritization (where relevant)** – BVES will analyze its entire service territory through this initiative.

5.7.3 RA-1-C. Develop verification and validation documentation for ignition models.

- **Problem statement** – PEDS is currently not in the DIREXYON Model
- **Planned Improvement** – Inclusion of this new risk component.
- **Anticipated Benefit** – BVES will be able to understand the benefits and risk associated with the PEDS component of the WMP.
- **Region prioritization (where relevant)** – BVES will analyze its entire service territory through this initiative.

5.7.4 RA-2-A.Develop verification and validation documentation for ignition models.

- **Problem statement** – As BVES transitions to the integrated software suite of DIREXYON and Technosylva, more rigorous internal protocols are necessary.
- **Planned Improvement** – Establish data transfer, quality control, and periodicity controls between BVES, Technosylva, and DIREXYON
- **Anticipated Benefit** – By establishing internal quality control standards and guidelines. BVES will be able to drive improvements to the process.
- **Region prioritization (where relevant)** – BVES will analyze its entire service territory through this initiative.

5.7.5 RA-3 Risk Presentation

- **Problem statement** – Upon completion of the DIREXYON software training and implementation protocols will need to be established.
- **Planned Improvement** – Completion of training on the software and the processes established in RA-1-A and RA-2-A
- **Anticipated Benefit** – BVES will have less reliance on contractors and manage the program internally.
- **Region prioritization (where relevant)** – BVES will analyze its entire service territory through this initiative.

Table 5-6 Utility Risk Assessment Improvement Plan

Proposed Improvement	Type of Improvement	Expected Value Add	Timeframe and Key Milestones
RA-1-A. Complete Integration of Direxyon and Technosylva Models	Programmatic: Training and process improvements on WFA-E use.	To improve data-driven decision making processes.	Pilot system, 2025–2026 Integrate system 2026–2027
RA-1-B. Develop verification and validation documentation for ignition models.	Technical: Inclusion of additional assets (i.e., arresters and connectors), refinement of vegetation treatment (i.e., separate asset instead of included in the pole asset), and refinement to the PSPS probability calculations.	Produce reliable quantitatively derived risk components and display them in a manner that is useful to decision makers.	Q4 2025 Implementation
RA-1-C. Develop verification and validation documentation for ignition models.	Technical: Inclusion of PEDS risk components.	Produce reliable quantitatively derived risk components and display them in a manner that is useful to decision makers.	Q4 2026 Implementation
RA-2-A. Develop wildfire mitigation programs and procedures to support use of integrated models.	Programmatic: Establish data transfer, quality control, and periodicity between BVES, Technosylva, and DIREXYON.	Establish internal quality control standards and guidelines.	Q4 2025 Implementation
RA-3. Risk Presentation	Technical and Programmatic: Complete the development of overall risk enterprise system and processes for control and use of system. Additionally, conduct staff training on system.	Produce reliable quantitatively derived risk components and display them in a manner that is useful to decision makers.	Q4 2025 Implementation

6. Wildfire Mitigation Strategy Development

6.1 Risk Evaluation

6.1.1 Approach

As BVES completes the transition to the DIREXYON tool, BVES continues to use a Risk-Based Decision-Making Framework in accordance with the approach for Small and Multi-Jurisdictional Utilities (SMJU) in CPUC D.19-04-020. The Risk-Based Decision-Making Framework prioritizes effective strategies for risk reduction. The methodology identifies inherent risk, existing controls, residual risk, and future mitigations after determining the likelihood and impact of wildfire. This is the primary tool for planning WMP initiatives. Sections 5.1 and 5.2.2 provide details regarding the process and the initial risk-ranking methodology.

6.1.1.1 Enterprise Risk Mitigation Strategy

The Risk Register Model quantifies mitigation projects and programs by the risk benefit and risk spend efficiency (RSE). This analysis reviews ongoing and potential projects to mitigate the three primary wildfire risk events: 1) Wildfire Public Safety, 2) Wildfire – Significant Loss of Property, and 3) Loss of Energy Supplies. See discussion in Section 5.2.2. BVES uses the output from this analysis to select the most cost effective and efficient projects. The enterprise risk evaluation considers a reasonable worst-case scenario for the three primary wildfire risk events. For each, BVES determined the frequency and impact scores for each of the weighted risk scoring inputs including system reliability impacts, regulatory compliance/legal implications, service to customers, public safety, and environmental impacts.

BVES utilizes a 7x7 log score matrix to determine an impact risk score for each weighted scoring input in the Risk Register. The weighted impact scores are accumulated to arrive at a total risk score. The risk scoring inputs, and total risk score form the basis of evaluation for each identified wildfire mitigation activity or initiative. Mitigation activities can be applied to a single or multiple risk events. BVES then calculates the risk reduction/risk benefit for each scoring input to arrive at a weighted mitigated risk score. The risk benefit for each combination of mitigation and risk event is determined by subtracting the mitigated risk score from the total risk score. BVES also defines an equivalent annual cost for each mitigation activity. Finally, the Risk Register determines the RSE by dividing the risk benefit by the equivalent annual cost.

6.1.1.2 Current and Future Locational Prioritization Tools

BVES's Fire Safety Circuit Matrix characterizes each BVES distribution circuit as high, moderate, and low risk and then prioritize the circuits within each risk group. The matrix data inputs include, inter alia, the number of customers, wood poles, bare wire overhead circuit miles, and tree attachments, which are then compiled and weighted to calculate the wildfire risk mitigation score. Currently, five circuits are rated high-risk, seven circuits are rated moderate risk, and fourteen circuits are rated low risk. (Note 2025 WMP reported 7 high risk, 12 moderate risk, and 7 low risk). BVES uses the Fire Safety Circuit Matrix as a "living document" as mitigations are implemented. BVES re-evaluates the mitigations, wildfire risk group, priority, and mitigation weight at least every six months. Additionally, the Fire Safety Circuit Matrix is used to gauge progress and set 3-year targets for the reduction of the wildfire mitigation score and associated wildfire ignition risk reduction.

In 2022, BVES hired Technosylva to advance the Risk Mapping Program and enhance situational awareness and improve resource allocation by leveraging the Wildfire Analyst Enterprise (WFA-E) software solution. This provides BVES with the following:

- Real-time wildfire behavior modeling, spread predictions, and potential impacts analysis
- Weather and wildfire risk forecasting for customer assets and the service territory to support PSPS activation calls and response operations
- Asset risk analysis using historical climatology to support mitigation planning

In 2023, Technosylva delivered FireSight. This model performs asset risk analysis using historical climatology as inputs and produces risk scenarios by running fire spread simulations for projected weather conditions. The model uses historical or predicted fuels data and runs millions of simulations across the customer service territory showing impact to assets.

BVES is in the process of transitioning from the Fire Safety Circuit Matrix to the DIREXYON to prioritize its WMP initiatives. Phase 1 of the DIREXYON conversion was completed in 2024. Updating the model with the latest asset data and FireSight data was not completed in time to for the 2026 WMP initiative work. The DIREXYON model will be used in future WMP updates. BVES believes that this change will provide a more detailed probabilistic model at the circuit and segment levels.

6.1.2 Risk-Informed Prioritization

BVES developed an initial prioritization list based on the Risk Register score. These prioritizations reflect a critical assessment of the risks associated with wildfire events. BVES assessed the initial prioritizations to identify any insights and considerations relevant to its decision-making process.

Technosylva's FireSight results were then reviewed to develop a list of all its circuits risks that identifies the highest consequence circuits for which it will prioritize the application of mitigation initiatives.

And finally, PSPS consequences surrogate are factored in using the values determined by the process in Section 5.2.2.2.

These circuits were ranked and provided in Table 5-5. Each of those circuits were reviewed using the process discussed below.

Risk Impact Categorization

BVES established Risk Impact Categories to assess the impact of an event. BVES also established descriptions in each category that describe increasing levels of severity from level 1 (negligible) to level 7 (catastrophic). These Risk Impact Category descriptions provide guidance for analyzing and scoring risk events. The descriptions provide a consistent framework to assign an impact value (level 1 to 7) to risk events across all five impact categories. BVES utilizes SME review and common industry practices to align worst case impact scores.

The Risk-Based Decision-Making Framework incorporates risk insights into utility investments and programs to inform the General Rate Case (GRC) cycles. This framework provides a process for identifying asset-related risks (including distribution assets and the Bear Valley Power Plant), consequences of occurrence, frequency or likelihood of occurrence, risk drivers, and mitigation measures. The results of the model identify strategic objectives for approval, categorize top risks to BVES and its service area including new and emerging risks, and arrive at risk-informed recommendations for future investments. This may also lead to modifying existing controls and implementation schedules.

Feasibility Constraints:

Feasibility constraints include limitations on data resolution, jurisdictional considerations, and accessibility.

The most significant feasibility constraints facing BVES are jurisdictional considerations, namely permitting, to perform work along the highest risk circuits which resides on USFS land and within their jurisdiction. This has led to permitting delays which lead to delays in installing covered conductors.

Bear Valley also experiences limitations on data resolution, but those limitations are offset by BVES's intimate familiarity with its compact service territory. Additionally, BVES has made significant improvements in its data acquisition, tracking, and utilization through its improved GIS performance, its use of the iRestore inspection/management activity interface, and its deployment of Technosylva's products.

BVES does not have any significant accessibility issues. Nearly all of BVES's overhead equipment can be accessed via truck on local roads.

Integrated Decision Making

The primary consideration is based on the FireSight input establishing those areas that will have the highest consequence (98th percentile acres burned). That is coupled with the areas likely to that are considered to have a higher likelihood of being under PSPS Consideration.

Table 6-1 List of Prioritized Areas in an Electrical Corporations Service Territory Based on Overall Utility Risk

Priority	Circuit	Length (miles)	Overall Utility Risk	Wildfire Risk	Outage Program Risk	Percent of Overall Utility Risk	Associated Risk Drivers
1	Baldwin	8.3	0.48	0.53	0.42	5.6%	Conductor failure
2	Boulder	17.5	0.59	0.66	0.51	6.9%	Conductor failure
3	Eagle	6.6	0.35	0.14	0.57	4.2%	Conductor failure
4	Castle Glen	6.9	0.32	0.13	0.52	3.8%	Conductor failure
5	Clubview	10.2	0.48	0.41	0.55	5.7%	Conductor failure
6	Erwin Lake	21.9	0.36	0.10	0.62	4.2%	None
7	Country Club	3.2	0.29	0.14	0.44	3.4%	Conductor failure
8	Interlacken	5.5	0.33	0.09	0.57	3.9%	Conductor failure

9	Georgia	4.8	0.28	0.07	0.48	3.3%	Conductor failure
10	North Shore	15.7	0.47	0.63	0.31	5.6%	Conductor failure
11	Goldmine	13.2	0.51	0.49	0.54	6.1%	Conductor failure
12	Holcomb	13.3	0.52	0.55	0.49	6.2%	Conductor failure
13	Harnish	1.5	0.23	0.10	0.35	2.7%	Conductor failure
14	Lagonita	6.7	0.28	0.16	0.39	3.3%	Conductor failure
15	Garstin	5.3	0.32	0.09	0.55	3.8%	Conductor failure
16	Radford	3.1	0.36	0.44	0.28	4.2%	Conductor failure
17	Paradise	9.8	0.30	0.14	0.47	3.6%	Conductor failure

18	Pump House	0.6	0.26	0.03	0.48	3.0%	Conductor failure
19	Shay	17.3	0.56	0.24	0.88	6.6%	None
20	Lift	0.0	0.03	0.06	0.00	0.4%	Conductor failure
21	Pioneer	16.4	0.44	0.62	0.26	5.2%	Conductor failure
22	Sunrise	7.6	0.36	0.14	0.58	4.3%	Conductor failure
23	Sunset	10.3	0.34	0.19	0.48	4.0%	Conductor failure

6.1.3 Activity Selection Process

BVES determines potential mitigation strategies based on the prioritized list of risks identified. Additionally, BVES evaluates the benefits and drawbacks of each strategy at different scales of application (e.g., circuit, circuit segment). BVES utilizes the processes and procedures discussed to develop, evaluate, and select mitigation initiatives.

6.1.3.1 Identifying and Evaluating Initiative Activities

This step is designed to identify and determine which projects are potentially viable to deliver consequential wildfire risk reduction. The outcome is an integrated list of projects with a basic understanding of project need, wildfire risk reduction value, timing, and execution challenges, such as permitting, equipment lag, workforce issues, etc. For each potential project, the risk reduction value and RSE are calculated using the Risk-Based Decision-Making Framework. This framework considers both safety (wildfire) and reliability (loss of power). For BVES to obtain a reasonable assessment of the risk reduction and RSE for each project, BVES seeks to understand to what degree will the risk reduction work be achieved and, if achievable or partly achievable, at what cost. The following factors are developed and considered by the management team:

- Desired scope of work (what technical specifications will the project achieve)
- Technology risk (is technology mature, used in California, new, etc.)
- Site availability and evaluation (constrained to existing facilities or new property; easements; access for construction, inspection, and O&M; zoning; endangered species, other protected species, cultural or historical concerns, or other environmental issues; impact on neighboring community during construction and following project, etc.)
- Permitting (are permits required; approval authority; complexity and timeline of permitting process; request from within the Company or contract out to a permitting expert consultant, etc.)
- Availability of material and equipment (delivery lead-time, type of material – special order made to specifications or commodity, etc.)
- Access to qualified labor resources (mobilization/demobilization, Company labor or contracted labor, work hours – day, night, weekends, shift work, etc.)
- Design process (design complexity; can the design be performed within the company, or must it be contracted out; timeline to produce construction grade design, design risk (e.g., during the course design, how likely is it that the scope of the project may be altered and by how much), etc.)
- Stakeholder support (internal approval, regulatory support, public and local stakeholder support)

- Length of construction period (multi-year, work all year-round or only during non-winter snow period, etc.)
- Project used and useful timeframe (as the project is constructed is it put in service, put in service in distinct phases, or at end of project)

From the above considerations, management analyzes the cost of the project, the estimated timeline and sequence of the project, and the risk reduction achieved according to the Risk-Based Decision-Making Framework for SMJUs. From this analysis, RSE is calculated.

An example of this is the Covered Conductor Replacement Project (GD_1). This project has the potential to lower the likelihood of ignitions and raise the threshold for PSPS events to higher wind speeds compared to bare conductor hardening. Undergrounding the 34 kV system would be the only other technically acceptable alternative. However, the cost would be over 10 times that of the covered wire replacement project. Additionally, certain areas present significant challenges to underground the overhead system. The Covered Wire Program therefore yields a more attractive RSE. BVES, therefore, decided to replace bare conductors with covered conductors on all sub-transmission lines (34.5 kV) and to replace all bare 4 kV distribution wire in high-risk areas within the service area with covered wire. In addition, this initiative is coupled with Distribution Pole Replacements and Reinforcements (GD_3) an ongoing program to proactively assess and remediate noncompliant distribution poles. Due to synergy with the Covered Conductor Replacement Project (Reconductor)(GD_1) initiative, for the period of this WMP, these initiatives are being conducted together. Before covered conductor is installed, each affected pole is fully assessed and those not meeting GO-95 requirements are replaced or remediated.

Note BVES is not required by the California Public Utilities Commission (CPUC) to develop either a Multi-Attribute Value Function (MAVF) or Multi-Attribute Risk Score (MARS) framework for Risk Assessment Mitigation Phase (RAMP) filings; however, BVES maintains a risk assessment toolkit to help identify risk drivers and better understand the potential consequences of wildfire threat while gauging the success of mitigation initiatives. This framework is the Risk-Based Decision-Making Framework in accordance with the safety model approach for Small and Multi-Jurisdictional Utilities (SMJU) provided in CPUC D. 19-04-020. Additionally, BVES is tracking current proceeding activities under R. 20-07-013, for which Safety Model and Assessment Proceeding (S-MAP) enhancements continue to be developed.

6.1.3.2 Initiative Activity Prioritization

Selection of Projects: In this step, management uses the information identified in the risk assessment to plan the optimal mix of projects to be included in the WMP (and follow-on updates to the WMP) to deliver maximum risk reduction considering BVES's limited capital and human resources. This process includes re-evaluating multi-year projects that are in progress to determine if they should be continued, discontinued, or revised. The expected outcome of this step is to develop an integrated and prioritized list of WMP projects to be executed in the next and future WMPs. The list of selected projects is not sequenced in this step. Alternatives to the projects are considered and some projects are removed from consideration in this step.

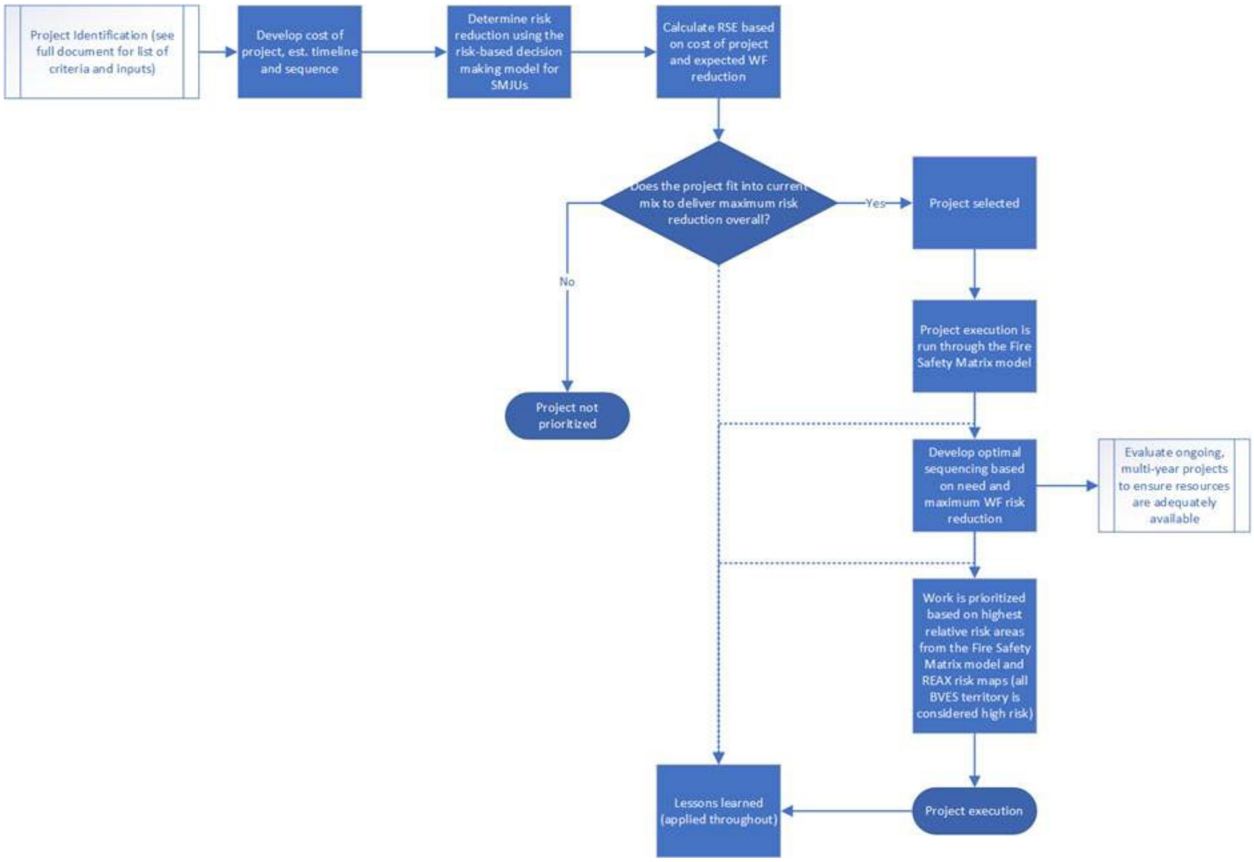
The risk reductions and RSEs, developed using the Risk-Based Making-Decision Framework, is utilized to establish an initial project selection screening. Then, the resulting risk mitigation outcome of executing the project is projected using the Fire Safety Circuit Matrix model described in Section 7.1.1 of this WMP. This provides more granular information at the circuit level. It should be noted that BVES's circuits are short in comparison to many utilities. The longest circuit is 23.9 circuit miles (8 of those circuit miles are underground) and most circuits are less than 10 circuit miles in length. Additionally, the projects are viewed against the risk maps developed by Technosylva to determine where the wildfire mitigation greatest risk benefit may be achieved by each project.

Each decision to plan an initiative recognizes that the utilities will not be bound to select mitigation strategies based solely on model outputs, and may consider other factors that inform initiative prioritization, including professional and engineering judgment, and resource constraints in terms of labor, equipment, and capital availability. Risk mitigation impacts will be quantified using monetized and standardized risk consequences to the most practicable extent; however, final prioritization choices will continue to be influenced by factors such as labor resources, technology, and modeling limitations and/or uncertainties affecting the analyses.

Relationships between initiatives is discussed in Section 6.1.2. SMEs contribute in the process during the selection of the project, the input to the Fire Safety Matrix and in the sequencing steps outlined in the process.

BVES Figure 6-1 depicts this process.

BVES Figure 6-1 Project Selection Process



Resource Optimization

BVES, as a small utility, completely located within HFTD Tiers 2 and 3, must maximize its resources to reduce wildfire and PSPS risk as much as possible with each initiative. A key factor in the selection of projects is a consideration of how each potential initiative will impact Bear Valley's labor force (both staff and contract labor) and ability to perform its core functions as well as achieve other safety, reliability, and performance objectives. It is imperative to BVES, its customers, and its stakeholders to optimize its resources to maximize risk reduction by employing the most efficient use of Bear Valley Resources.

6.1.3.3 Initiative Activity Scheduling

BVES management uses its risk assessment processes and tools to develop the optimal sequence to execute the selected WMP projects to deliver the maximum wildfire risk reduction while balancing constraints (siting, designing, permitting, costs, access to labor, availability of equipment and material, mobilization/demobilization, etc.). This process also includes re-evaluating the pace and order for which in-progress multi-year projects are to be executed, or even paused. The expected outcome of this step is to develop a well-sequenced WMP integrated risk-based project plan by year. The plan's 1-3-year horizon is well-defined, the 4-5 year horizon is projected with as much detail as feasible, and the 6-10-year horizon is more notional.

This step focuses on allocating resources to execute projects, incorporating project constraints (siting, designing, permitting, costs, access to labor, availability of equipment and material, mobilization/demobilization, etc.), in a risk-based prioritized manner based on the information from the prior steps. A project may have a large risk reduction but permitting for the project is lengthy and may still be in progress; therefore, other projects with consequential risk benefit are sequenced ahead of the high risk-benefit project until it is ready to execute. This approach allows BVES to continuously make risk reduction progress in its grid hardening efforts. This step also considers other projects being executed and how best to seize synergy opportunities, improve resource allocation efficiency, stay focused on achieving the greatest risk reduction, and coordinate between projects to avoid inefficiencies, unnecessary delays, and re-work.

In sequencing projects, the focus is maximizing risk reduction. BVES prioritizes and plans work based upon the highest relative risk areas as determined in the Fire Safety Circuit Matrix described in Section 6.1.1 of this WMP as modified by the Technosylva FireSight and PSPS risk surrogate. As detailed in Section 4, Bear Valley's entire 32 square-mile service area is "high risk," considered "Very Dry" or "Dry" per the National Fire Danger Rating System (NFDRS) over 75 percent of the time and is characterized with a high density of vegetation – trees and shrubs. The CPUC Fire-Threat Map adopted January 19, 2018, designated Bear Valley's entire service area as within the High Fire-Threat District (HFTD) with approximately 90% in Tier 2 (elevated risk) and the remaining 10% in Tier 3 (extreme risk) areas. The Cal Fire California Fire Hazard Severity Zone Map Update Project rates Bear Valley's service area as "Very High Fire Hazard Severity Zone." While one can rank the relative risk of BVES's facilities within the service area, BVES's entire service area is high risk. In such a small service area, an ignition anywhere can produce embers that the wind can carry just a few blocks away and cause a wildfire.

Project Progress Monitoring

BVES management tracks implementation of each mitigation project and initiative closely. Due to the size of the staff and service territory, all projects have full visibility up to the highest level of the utility. Additionally, staff conduct weekly management briefings and management reports to track progress, project needs, challenges, and delays, if any, on every project. Major initiative targets are reviewed at least weekly by management.

Project Execution Lessons Learned

Lessons are learned at every step of the process, and it is inefficient to wait to make course corrections where appropriate. Therefore, BVES management uses its experience as well as external information to incorporate and address pertinent lessons learned in executing the WMP projects to deliver the maximum wildfire risk reduction while considering constraints. Lessons learned are not just limited to project execution but also from other utilities' experiences, updates from industry group (e.g., Institute of Electrical and Electronics Engineers (IEEE), National Electrical Safety Code (NESC), etc.), vendor and manufacturer updates, etc. The intended outcome is developing knowledge from both experience and external sources that will inform the entire WMP project cycle to create a process for continual improvement.

Lessons learned and best practices are discussed by the BVES management team at weekly meetings to promote continuous improvement in project processes.

Risk models are re-evaluated to ensure resources are allocated using the best information available at the time.

6.1.3.4 Key Stakeholders for Decision Making

BVES identifies all key stakeholder groups that are part of the decision-making process for developing and prioritizing mitigation initiatives. The roles and responsibilities, engagement methods, mitigation initiative, and level of engagement (i.e. local, tribal, federal) are included in Table 6-2.

Table 6-2 Stakeholder Roles and Responsibilities in the Decision-Making Process

Stakeholder	Stakeholder Point of Contact	Electrical Corporation Point of Contact	Stakeholder Role	Engagement Methods	Mitigation Initiative Activity	Level of Engagement for Mitigation Initiative Activity
Sheriff's Department Big Bear Lake Patrol Station	Sherriff	Paul Marconi	• Evacuation Routes – decision maker • PSPS Coordination - informed	• Quarterly public meetings • Phone calls as needed	• Emergency preparedness and recovery plan (EP_1) • External collaboration and coordination (EP_2) • Public communication, outreach, and education (EP_3)	Local
Big Bear Fire Department	Fire Chief	Paul Marconi	• Policy - consulted • Coordinate emergency response - consulted • Wildfire mitigation – decision maker	• Quarterly meetings • Phone calls as needed	• Emergency preparedness and recovery plan (EP_1) • External collaboration and coordination (EP_2) • Public communication, outreach, and education (EP_3) • Wildfire Mitigation Strategy Development (WMSD_1) • Emergency response vegetation management (VM_13) • Post-fire service restoration (VM_14) • Fall-in Mitigation and High-risk Species (VM_8) • Clearance (VM_9)	Local
San Bernadino County	Big Bear Lake Representative for County Supervisor 3rd District	Paul Marconi	• Policy - consulted • Communication - informed	• Bi-annual meetings • Phone calls as needed	• Emergency preparedness and recovery plan (EP_1) • External collaboration and coordination (EP_2) • Public communication, outreach, and education (EP_3) • Wildfire Mitigation Strategy Development (WMSD_1)	Local
Cal Trans	Transportation Engineer	Tom Chou	• Grid hardening coordination - informed • PSPS coordination - informed • Permitting – decision maker	• Quarterly meetings • Phone calls as needed	• Emergency preparedness and recovery plan (EP_1) • External collaboration and coordination (EP_2) • Public communication, outreach, and education (EP_3)	Local
City of Big Bear Lake	City Manager Director of Public Service/City Engineer	Paul Marconi	• Policy – consulted • Permitting – consulted • Communication – consulted	• Quarterly public meetings • Phone calls as needed	• Emergency preparedness and recovery plan (EP_1) • External collaboration and coordination (EP_2) • Public communication, outreach, and education (EP_3) • Wildfire Mitigation Strategy Development (WMSD_1)	Local
Mountaintop San Bernadino US Forrest Service	District Ranger	Paul Marconi	• Grid hardening coordination – consulted • Vegetation management – consulted • Permitting – decision maker	• Phone calls as needed	• Emergency preparedness and recovery plan (EP_1) • External collaboration and coordination (EP_2) • Public communication, outreach, and education (EP_3) • Pole clearing (VM_10)	Federal

					• Wood and slash management (VM_11) • Emergency response vegetation management (VM_13) • Post-fire service restoration (VM_14) • Fall-in Mitigation and High-risk Species (VM_8) • Clearance (VM_9) • Wildfire Mitigation Strategy Development (WMSD_1)	

6.2 Wildfire Mitigation Strategy

BVES's implementation strategy for each mitigation initiative selected in accordance with the risk-informed process discussed in Section 6.1, is displayed in Table 6-3 below Table 6-3 provides a cross reference to the details regarding each mitigation initiative.

In general, the three-year objectives include the following:

- Additional grid hardening efforts,
- Increased situational awareness and control improvements expected from completion of the grid automation initiatives,
- Continued vegetation management, asset inspections, and equipment maintenance/repairs
- Real-time fire risk modeling, and
- Increased resiliency to serve load via local generation through the solar and storage projects.

BVES expects to make continued and substantial progress in replacing all sub-transmission bare wire with covered wire. BVES will also begin to harden secondary evacuation routes throughout the service area.

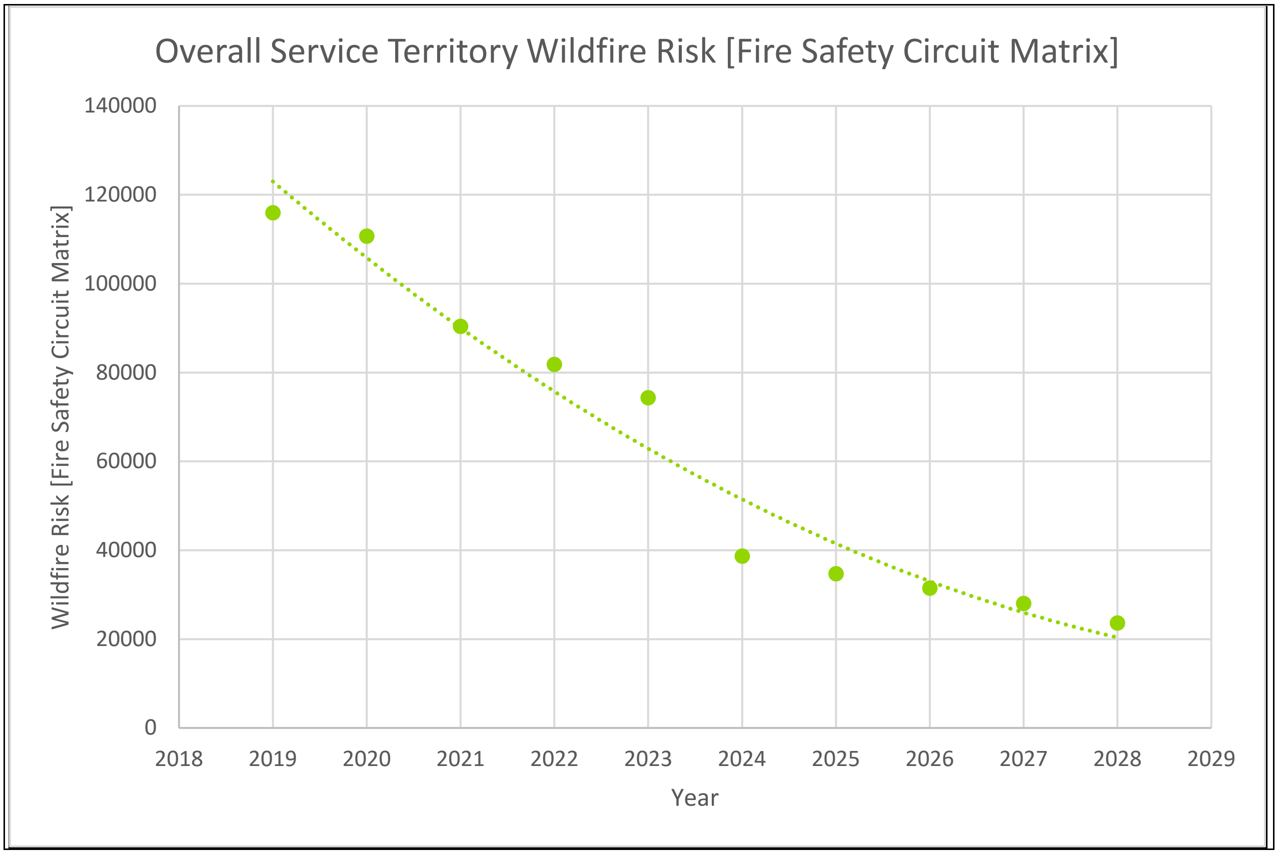
6.2.1 Anticipated Risk Reduction

In the subsections below, BVES presents the expected risk reduction for each mitigation and the schedule on which it plans to implement the mitigation initiatives.

6.2.1.1 Projected Overall Risk Reduction

BVES' overall service area risk reduction depicted in Figure 6-2 and intends to provide an integrated view of wildfire risk reduction across its service territory over the next 10 years.

Figure 6-1 Overall Service Territory Wildfire Risk



6.2.1.2 Risk Impact of Initiative Activities

Using the Risk-Based Decision-Making Framework resulting Risk Register the following information is derived for both wildfire and PSPS risk:

- An unmitigated risk score
- A mitigated risk score
- A RSE

Table 6-3 lists each of the initiatives and presents the results of the following calculations:

Activity Effectiveness

- Activity Effectiveness – Wildfire
  (((Unmitigated Risk – Mitigated Risk) / Unmitigated Risk))*100
- Activity Effectiveness – PSPS
  (((Unmitigated Risk – Mitigated Risk) / Unmitigated Risk))*100
- Activity Effectiveness – Overall is the average of Wildfire and PSPS effectiveness

Cost-Benefit

- Cost Benefit – Wildfire
  (Unmitigated Risk – Mitigated Risk) / Initiative Cost)
- Cost Benefit – PSPS
  (Unmitigated Risk – Mitigated Risk) / Initiative Cost)
- Cost Benefit – is the average of Wildfire and PSPS Cost Benefit

% HFRA

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 Base plan to the last year of the Base plan. This was calculated the number of circuit miles or the number of assets as follows:
(units of activity/units of activity within the HFTD)*100

Table 6-3 Risk Impact of Initiative Activities

Initiative Activity	Initiative Activity Section #	Activity Effectiveness – Overall Risk	Activity Effectiveness – Wildfire Risk	Activity Effectiveness – Outage Program Risk	Cost-Benefit Score – Overall Risk	Cost-Benefit Score – Wildfire Risk	Cost-Benefit Score – Outage Program Risk	% HFRA Covered	Expected % Risk Reduction52	Model(s) Used to Calculate Risk Impact
ENT_1: Asset management and inspection enterprise system(s)	12.2	4.9%	3.1%	6.7%	0.72	0.64	0.80	NA	4.9%	Risk Register
ENT_2: Vegetation management enterprise system	12.2	4.9%	3.1%	6.7%	0.72	0.64	0.80	NA	4.9%	Risk Register
EP_1: Emergency preparedness and recovery plan	11.2	4.9%	3.1%	6.7%	3.83	3.43	4.24	NA	4.9%	Risk Register
EP_2: External collaboration and coordination	11.1, 12.1	4.9%	3.1%	6.7%	1.02	0.91	1.13	NA	4.9%	Risk Register
EP_3: Public communication, outreach, and education	11.1, 12.1	4.9%	3.1%	6.7%	0.32	0.29	0.35	NA	4.9%	Risk Register
EP_4: Customer support in wildfire and PSPS emergencies	11.1, 12.1	4.9%	3.1%	6.7%	5.11	4.57	5.65	NA	4.9%	Risk Register
GD_1: Covered Conductor Replacement Project (Reconductor)	8.2.1, 8.4.4, 8.4.9	5.8%	5.5%	6.2%	0.22	0.27	0.17	38%	5.8%	Risk Register
GD_10: Fuse TripSaver Automation	8.2.8, 8.4.5	2.5%	3.7%	1.4%	2.30	3.81	0.80	20%	2.5%	Risk Register

GD_11: Non-Exempt Surge Arrester Replacement	8.2.10	5.1%	3.5%	6.7%	0.59	0.56	0.63	100%	5.1%	Risk Register
GD_12: Tree Attachment Removal Project	8.2.10	5.3%	5.6%	5.1%	1.22	1.60	0.84	100%	5.3%	Risk Register
GD_13: Safety and Technical Upgrades to Lake Substation	8.2.12	5.7%	4.7%	6.7%	0.03	0.04	0.03	100%	5.7%	Risk Register
GD_14: Partial Safety and Technical Upgrades to Village Substation	8.2.12	5.7%	4.7%	6.7%	0.04	0.04	0.03	100%	5.7%	Risk Register
GD_15: Equipment maintenance and repair	8.4.3	5.6%	4.3%	6.8%	0.03	0.03	0.03	100%	5.6%	Risk Register
GD_16: Asset Quality assurance / quality control	8.5.4	5.6%	4.5%	6.7%	1.91	2.06	1.77	NA	5.6%	Risk Register
GD_17: Asset Open work orders	8.6	5.1%	3.4%	6.7%	1.63	1.53	1.72	NA	5.1%	Risk Register
GD_18: Equipment Settings to Reduce Wildfire Risk	8.7.1	7.6%	8.5%	6.7%	0.72	0.99	0.45	100%	7.6%	Risk Register
GD_19: Grid Response Procedures and Notifications	8.7.2	4.9%	3.1%	6.7%	3.20	2.86	3.54	NA	4.9%	Risk Register
GD_2: Minor Undergrounding Upgrades Projects	8.2.2	4.9%	3.1%	6.7%	0.19	0.17	0.21	100%	4.9%	Risk Register

GD_20: Personnel Work Procedures and Training in Conditions of Elevated Fire Risk	8.7.3	4.9%	3.1%	6.7%	7.21	6.44	7.97	NA	4.9%	Risk Register
GD_21: Asset Workforce Planning	8.7.4	4.9%	3.1%	6.7%	4.43	3.96	4.90	NA	4.9%	Risk Register
GD_22: Detailed inspections	8.3.1	5.7%	4.7%	6.7%	2.35	2.56	2.13	100%	5.7%	Risk Register
GD_23: Patrol Inspections	8.3.2	5.7%	4.7%	6.7%	1.01	1.10	0.91	100%	5.7%	Risk Register
GD_24: UAV Thermography Inspections	8.3.3	5.7%	4.7%	6.7%	0.22	0.25	0.20	100%	5.7%	Risk Register
GD_25: UAV HD Photography/Videography Inspections	8.3.4, 8.4.7	5.7%	4.7%	6.7%	0.22	0.25	0.20	100%	5.7%	Risk Register
GD_26: 3rd Party Ground Patrol Inspections	8.3.5	5.7%	4.7%	6.7%	0.56	0.61	0.51	100%	5.7%	Risk Register
GD_27: Intrussive Pole Inspections	8.3.6	5.7%	4.7%	6.7%	1.85	2.02	1.68	100%	5.7%	Risk Register
GD_28: Substation inspections	8.3.7	5.7%	4.7%	6.7%	0.32	0.35	0.29	100%	5.7%	Risk Register
GD_3: Covered Conductor Replacement Project (Pole Assessment)	8.2.3, 8.4.6, 8.4.7	5.8%	5.5%	6.2%	0.52	0.63	0.40	38%	5.8%	Risk Register

GD_4: Evacuation Route Hardening Project	8.2.3, 8.4.6, 8.4.7	5.6%	5.6%	NA	1.99	1.99	NA	31%	5.6%	Risk Register
GD_5: Traditional overhead hardening	8.2.5, 8.4.1, 8.4.2, 8.4.11	5.7%	4.7%	6.7%	0.09	0.09	0.08	100%	5.7%	Risk Register
GD_6: Solar Energy Project	8.2.7	18.0%	NA	18.0%	0.01	NA	0.01	100%	18.0%	Risk Register
GD_7: Energy Storage Project	8.2.7	18.0%	NA	18.0%	0.02	NA	0.02	100%	18.0%	Risk Register
GD_8: Switch and Field Device Automation	8.2.8, 8.4.8	6.1%	4.4%	7.8%	0.63	0.63	0.64	22%	6.1%	Risk Register
GD_9: Capacitor Bank Upgrade Project	8.2.8, 8.4.1	3.8%	5.2%	2.4%	0.64	1.02	0.27	100%	3.8%	Risk Register
RMA_1: Risk Methodology and Assessment	5.7	6.5%	3.5%	9.5%	0.52	0.41	0.64	100%	6.5%	Risk Register
SAF_1: Advanced weather monitoring and weather stations	10.2	5.5%	4.3%	6.7%	2.89	3.06	2.72	100%	5.5%	Risk Register
SAF_2: Install Fault Indicators	10.3	5.1%	3.4%	6.7%	3.69	3.48	3.91	100%	5.1%	Risk Register
SAF_3: Online Diagnostic System	10.3	5.5%	4.3%	6.7%	2.67	2.82	2.51	100%	5.5%	Risk Register

SAF_4: Autonomous Monitoring of Power Line Infrastructure	10.4	5.7%	4.7%	6.8%	0.10	0.11	0.09	100%	5.7%	Risk Register
SAF_5: ALERT Wildfire Cameras	10.4	4.9%	3.1%	6.7%	3.78	3.38	4.18	100%	4.9%	Risk Register
SAF_6: Weather forecasting	10.5	4.9%	3.1%	6.7%	0.33	0.29	0.36	100%	4.9%	Risk Register
SAF_7: Fire potential index	10.6	7.1%	4.7%	9.5%	0.79	0.73	0.85	100%	7.1%	Risk Register
VM_1: Detailed inspections	9.2.1	5.7%	4.7%	6.7%	2.35	2.56	2.13	100%	5.7%	Risk Register
VM_10: Pole clearing	9.4	5.6%	4.3%	6.8%	0.11	0.11	0.10	100%	5.6%	Risk Register
VM_11: Wood and slash management	9.5	5.7%	4.7%	6.8%	0.01	0.01	0.01	100%	5.7%	Risk Register
VM_12: Substation defensible space	9.6	4.9%	3.1%	6.8%	1.92	1.72	2.13	100%	4.9%	Risk Register
VM_13: Emergency response vegetation management	9.9	4.0%	1.2%	6.7%	0.61	0.29	0.92	NA	4.0%	Risk Register
VM_14: Post-fire service restoration	9.1	4.9%	3.1%	6.7%	5.54	4.95	6.13	NA	4.9%	Risk Register

VM_15: Vegetation Management Quality assurance / quality control	9.11	4.9%	3.1%	6.7%	0.46	0.41	0.51	NA	4.9%	Risk Register
VM_16: Vegetation Management Open work orders	9.12	4.9%	3.1%	6.7%	0.69	0.61	0.76	NA	4.9%	Risk Register
VM_17: Vegetation Management Workforce planning	9.13	4.9%	3.1%	6.7%	3.68	3.29	4.07	NA	4.9%	Risk Register
VM_2: Patrol Inspections	9.2.2	5.7%	4.7%	6.7%	1.01	1.10	0.91	100%	5.7%	Risk Register
VM_3: UAV HD Photography/Videography Inspections	9.2.3	5.7%	4.7%	6.7%	0.22	0.25	0.20	100%	5.7%	Risk Register
VM_4: LiDAR inspections	9.2.4	5.7%	4.7%	6.7%	0.30	0.32	0.27	100%	5.7%	Risk Register
VM_5: 3rd Party Ground Patrol Inspections	9.2.5	5.7%	4.7%	6.7%	0.56	0.61	0.51	100%	5.7%	Risk Register
VM_6: Substation inspections	9.2.6	5.7%	4.7%	6.7%	2.61	2.85	2.36	100%	5.7%	Risk Register
VM_7: Satellite Imaging Inspections	9.2.7	5.7%	4.7%	6.7%	0.88	0.96	0.80	100%	5.7%	Risk Register
VM_8: Fall-in Mitigation and High-risk Species	9.3	9.2%	11.6%	6.8%	0.13	0.20	0.07	100%	9.2%	Risk Register

VM_9: Clearance	9.3	9.2%	11.6%	6.8%	0.03	0.05	0.02	100%	9.2%	Risk Register
WMSD_1: Wildfire Mitigation Strategy Development	6.0	5.1%	3.5%	6.7%	0.80	0.76	0.85	NA	5.1%	Risk Register

6.2.1.3 Projected Risk Reduction on Highest-Risk Circuits Over the Three-Year WMP Cycle

BVES's service area risk reduction provides an integrated view of wildfire risk reduction across its service territory from 2026-2028.

Table 6-4 Summary of Risk Reduction for Top-Risk Circuits

Circuit	2025 Overall Utility Risk	2026 Initiative Activities	2026 Overall Utility Risk	2027 Initiative Activities	2027 Overall Utility Risk	2028 Initiatives Activities	2028 Overall Utility Risk
Boulder	4949	GD_1: Covered Conductor Replacement Project (Reconductor) GD_3: Covered Conductor Replacement Project (Pole Assessment)	3535	None	3535	GD_1: Covered Conductor Replacement Project (Reconductor) GD_3: Covered Conductor Replacement Project (Pole Assessment)	2323
Goldmine	4492	None	4492	None	4492	None	4492
North Shore	4045	None	4045	GD_1: Covered Conductor Replacement Project (Reconductor) GD_3: Covered Conductor Replacement Project (Pole Assessment)	3087	GD_1: Covered Conductor Replacement Project (Reconductor) GD_3: Covered Conductor Replacement Project (Pole Assessment)	1171
Clubview	3497	None	3497	None	3497	GD_1: Covered Conductor Replacement Project (Reconductor) GD_3: Covered Conductor Replacement Project (Pole Assessment)	2285
Pioneer	2506	None	2506	GD_1: Covered Conductor Replacement Project (Reconductor) GD_3: Covered	1	None	1

				Conductor Replacement Project (Pole Assessment)			
Holcomb	2447	GD_1: Covered Conductor Replacement Project (Reconductor) GD_3: Covered Conductor Replacement Project (Pole Assessment)	629	None	629	None	629
Sunset	1790	None	1790	None	1790	None	1790
Lagonita	1389	None	1389	None	1389	None	1389
Sunrise	1309	None	1309	None	1309	None	1309
Eagle	1296	None	1296	None	1296	None	1296
Castle Glen	1186	None	1186	None	1186	None	1186
Paradise	964	None	964	None	964	None	964
Interlacken	775	None	775	None	775	None	775
Harnish	716	None	716	None	716	None	716
Radford	644	None	644	None	644	None	644
Lift	627	None	627	None	627	None	627
Garstin	604	None	604	None	604	None	604
Georgia	594	None	594	None	594	None	594
Country Club	514	None	514	None	514	None	514
Baldwin	342	None	342	None	342	None	342
Pump House	11	None	11	None	11	None	11
Shay	1	None	1	None	1	None	1
Erwin Lake	1	None	1	None	1	None	1

6.2.2 Interim Initiative Activities

BVES assesses each mitigation that requires more than one year to implement for the potential need for interim mitigation strategies to reduce risk until the primary mitigation is complete. BVES develops and implements interim strategies if determined necessary. BVES utilizes the approach discussed in Section 6.1.3.3 to evaluate the need for interim risk reduction, determining which mitigations to implement, and the characterization of each interim risk reduction action. The following initiatives are multi-year program:

- Covered Conductor Replacement Project (Reconductor)(GD_1)
- Covered Conductor Replacement Project (Pole Assessment)(GD_3)

The interim mitigations for bare conductor circuits that are awaiting covered conductor replacement are: (1) lower PSPS thresholds, (2) implementation of EPSS, (3) reclosing in manual, and (4) prioritized detailed and patrol inspections.

7. Public Safety Power Shutoff

7.1 Overview

The purpose of public safety power shutoffs (PSPS) is to promote public safety by decreasing the risk of utility infrastructure being a source of wildfire ignitions. Bear Valley considers PSPS to be a measure of last resort, driven by a combination of extreme fire threat weather, fuel moisture, wind, and situational awareness information to protect the community against ignition threats from energized circuits.

Bear Valley has not experienced the environmental conditions that exceed its PSPS thresholds; therefore, Bear Valley has never invoked a PSPS on any of its circuits. Although BVES has never implemented PSPS, BVES is committed to reducing the scope, frequency, and duration of PSPS events, should it be necessary when the safety risk of imminent fire danger is greater than the impact of de-energization.

However, the BVES service area is susceptible to several conditions in which PSPS will have a direct impact on its customers. These are:

- Bear Valley directs PSPS on its power lines and facilities due to extreme fire threat weather and conditions that warrant implementation of PSPS;
- Southern California Edison (SCE) directs PSPS on its power lines and facilities due to conditions exceeding SCE's PSPS thresholds within its service area, leading to a partial or complete loss of the SCE supply power lines to Bear Valley's service area; or
- Combination of the above.

Section 7.3 discusses Bear Valley's PSPS thresholds in more detail but they are summarized here to provide context for the following discussion. To summarize the PSPS thresholds, they are based on the Fire Potential Index (FPI) and the circuit condition as follows:

- When FPI is "High" and:
    - Wind speed 40 mph or more on bare conductor circuits
    - Wind speed 50 mph or more on bare conductor circuits with EPSS enabled
    - Wind speed 65 mph or more on covered conductor circuits

- When FPI is "Very High" or "Extreme" and:
    - Wind speed 35 mph or more on bare conductor circuits
    - Wind speed 45 mph or more on bare conductor circuits with EPSS enabled
    - Wind speed 65 mph or more on covered conductor circuits

Wind speed refers to actual or forecasted for sustained winds or wind gusts of 3 seconds or more.

Figure 7-1 Highest Daily Wind Gust and Sustained Wind on High-Risk Days below correlate high wind events (gusts and sustained winds) with High-Risk Days (days with NFDRS that are Brown, Orange, or Red) over the past 10 years. The data indicates that the threshold for BVES to direct a PSPS event was not experienced in the BVES service area.

Figure 7-1 Highest Daily Wind Gust and Sustained Wind on High-Risk Days

Highest Daily Wind Gust on High Risk Days										
Wind Gusts	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
>55	0	0	0	0	0	0	0	0	0	0
50 to 54	0	0	0	0	0	0	0	0	0	0
40 to 49	1	0	0	0	1	1	2	0	0	0
30 to 39	7	7	5	6	1	5	5	1	1	1
20 to 29	43	78	39	64	27	65	51	40	40	12
<20	56	66	74	59	58	90	27	23	28	11
Highest Daily Sustained Wind on High Risk Days										
Wind Gusts	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
>55	0	0	0	0	0	0	0	0	0	0
50 to 54	0	0	0	0	0	0	0	0	0	0
40 to 49	0	0	0	0	0	0	0	0	0	0
30 to 39	0	0	0	0	0	0	1	0	0	0
20 to 29	7	2	6	5	3	7	4	2	2	0
<20	100	149	112	124	84	154	83	80	79	28

Figure 7-2 National Fire Danger Rating System (NFDRS) Historic Data below indicates that Bear Valley's service area experienced High-Risk Days (days with NFDRS that are Brown, Orange, or Red) over the past 10 years about 28.9% of the time. If winds were to exceed PSPS thresholds on these days, PSPS events would be invoked on affected circuits or segments. Therefore, it is imperative that BVES continue to reduce ignition risk, monitor and forecast the likelihood of the need to use PSPS, have PSPS procedures in place, and be trained and proficient at PSPS procedures.

Figure 7-2 National Fire Danger Rating System (NFDRS) Historic Data

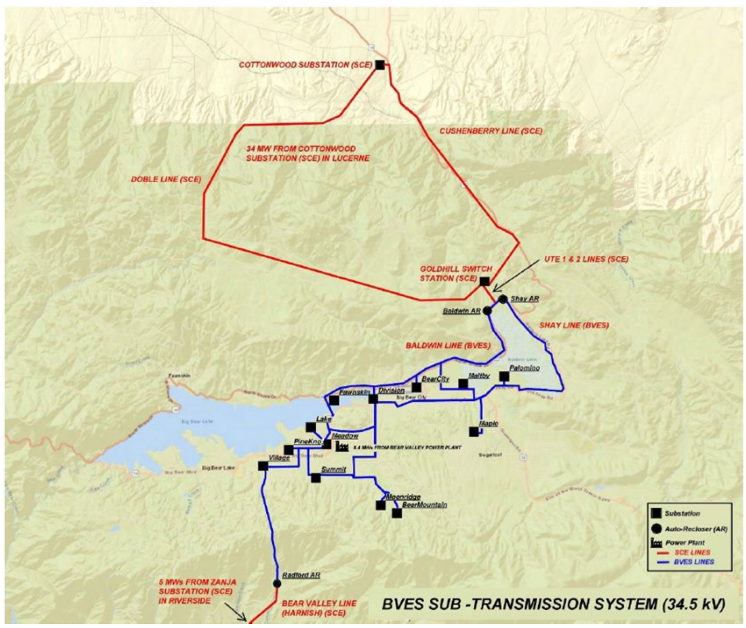
NFRDS	2015	2016	2017	2018*	2019*	2020	2021	2022	2023	2024
G-Low Risk	26	71	109	26	189	108	87	130	130	212
Y-Moderate Risk	232	144	138	169	66	97	187	152	152	126
B-High Risk	105	138	103	122	78	152	90	83	83	25
O-High Risk	0	9	15	7	9	6	0	0	0	0
R-High Risk	2	4	0	0	0	3	0	0	0	3
*NFDRS not available for some days due to Federal Government shutdown.										

Bear Valley has included initiatives in this WMP that are designed to reduce the need for, and impact of, future PSPS implementation. Impacts include: duration, frequency, and scope – number of customers.

7.2 SCE Directed PSPS

Currently, the highest probability of customers experiencing the impact of a PSPS event within the BVES service territory is the loss of SCE's supply power lines to the BVES service area due to an SCE-directed PSPS of the SCE supply power lines. BVES imports from SCE are subject to PSPS activation initiated by SCE. SCE may activate a PSPS due to conditions in SCE's service area even though conditions in the BVES service area would not reach BVES PSPS thresholds. For example, it is quite possible that SCE power lines that supply Bear Valley's service area exceed SCE PSPS thresholds within SCE's service area (for example, the foothills of the mountains where wind speeds can reach 85 mph during a Santa Ana event) causing SCE to activate a PSPS on its supply power lines to BVES even if these circuits within the BVES service area do not meet Bear Valley's PSPS thresholds. **Figure 7-3 BVES Supply Lines, Sources of Power and Sub-Transmission System** provides a graphic on how the SCE supply power lines interact with the BVES system.

Figure 7-3 BVES Supply Lines, Sources of Power and Sub-Transmission System



To address the possibility of SCE-directed PSPS events, BVES has implemented initiatives in the Grid Design, Operations, and Maintenance Category (Section 8) and Emergency Preparedness and Community Outreach Category (Section 11).

BVES is pursuing the Bear Valley Solar Energy Project (GD_6) and Bear Valley Energy Storage Project (GD_7) initiatives (A.24-05-020 filed with the CPUC on May 17, 2024), which would significantly reduce PSPS risk to Bear Valley's customers by allowing BVES to supply power to its customers. In conjunction with the existing Bear Valley Power Plant and these initiatives, BVES would be able to initially meet its energy demands during a supply drop from SCE for several hours depending on load shedding strategy.

- Bear Valley's Emergency Preparedness and Recovery Plan (EP_1) initiative provides operational procedures that reduce the duration and scope of SCE PSPS events as follows:
    - BVES Public Safety Power Shutoff Procedures (provided in Appendix G to this WMP) provide BVES staff comprehensive procedures regarding PSPS including loss of supply line strategies (SCE PSPS).
    - BVES Emergency Response and Disaster Plan (provided in Appendix F to this WMP) provides BVES staff comprehensive emergency operations procedures, including procedures for operating its Emergency Operations Center, emergency operations organization structure and response, restoration strategies, loss of supply line strategies (SCE PSPS), mutual aid support, and customer and stakeholder communications. BVES Public Safety Power Shutoff Procedures (provided in Appendix G to this WMP) provide specific procedures to address partial or complete loss of power due to SCE supply power line PSPS events.

Close coordination between SCE and BVES staff is essential in mitigating the impacts of an SCE PSPS event. BVES is included in the SCE Incident Management Team (IMT) briefs and receives notifications directly from the SCE IMT, the SCE Account Manager to BVES accounts, and the operators at SCE Lugo and Colton Control Stations. **Figure 7-4 BVES Action for SCE Lines Under PSPS Consideration** below from BVES Public Safety Power Shutoff Procedures provides specific guidance to Bear Valley's staff when SCE power lines are under PSPS consideration or in scope for PSPS.

Figure 7-4 BVES Action for SCE Lines Under PSPS Consideration

Condition	BVES Action
SCE places Doble or Cushenberry Line under PSPS Consideration.	1. Notify key internal staff and brief Field Operations staff on condition for situational awareness. 2. Operations & Planning Manager evaluates energizing Radford Line for improved reliability.
SCE places Bear Valley Line under PSPS Consideration.	1. Notify key internal staff and brief Field Operations staff on conditions for situational awareness. 2. If Radford is energized, shift loads to Shay Line.
SCE places Doble <u>and</u> Cushenberry Lines under PSPS Consideration.	1. Notify key internal staff and brief Field Operations staff on condition for situational awareness. 2. Energize the Radford Line. 3. Prepare for potentially losing all SCE supply lines from Lucerne. 4. Prepare for sustained BVPP operations and rolling blackouts. 5. Evaluate distribution circuit loads.
SCE places Doble or Cushenberry, and Bear Valley Lines under PSPS Consideration	1. Notify key internal staff and brief Field Operations staff on condition for situational awareness. 2. Prepare for potentially losing all SCE supply lines from Lucerne. 3. Prepare for sustained BVPP operations and rolling blackouts. 4. Evaluate distribution circuit loads.
SCE places Doble, Cushenberry, and Bear Valley Lines under PSPS Consideration	1. Notify key internal staff and brief Field Operations staff on condition for situational awareness. 2. Prepare for potentially losing all SCE supply lines into BVES service area. 3. Prepare for sustained BVPP operations and rolling blackouts. 4. Evaluate distribution circuit loads.

Figure 7-5 BVES Action for SCE Lines De-energized Due to PSPS from BVES Public Safety Power Shutoff Procedures provides procedures to use in the event of a partial or complete loss of SCE supply power lines. These procedures are based on the BVES Emergency Response and Disaster Plan and take into account that BVES will closely coordinate with SCE Staff to achieve the following notification goals:

- SCE should provide warnings of impending PSPS on the SCE lines about 2 days prior to the event.
- SCE should provide updates to the status of the lines under PSPS consideration.
- SCE should notify BVES at least 4 hours prior to de-energizing any SCE supply lines to BVES service area.
- SCE should provide BVES “de-energization imminent” notification at least 1 hour prior to de-energizing any SCE supply lines to BVES service area.

These timely notifications will allow BVES to take preparatory action to shed load to within the expected capacity of its remaining sources of power and allow BVES to avoid a “blackstart” on the Bear Valley Power Plant. Therefore, the procedures outlined below in **Figure 7-5 BVES Action for SCE Lines De-energized Due to PSPS** should be followed during a SCE PSPS event.

Figure 7-5 BVES Action for SCE Lines De-energized Due to PSPS

Condition	BVES Action
SCE De-energizes Doble or Cushenberry Line for PSPS.	1. Notify key staff and brief Field Operations staff on condition for situational awareness. 2. Energize Radford Line if needed to meet load demand and reliability. 3. Start up the BVPP as needed to meet load demand. 4. No reduction in load necessary, since the Doble and Cushenberry are capable of carrying the other's load. 5. Implement BVES EDRPn for a partial loss of SCE supply lines.
SCE De-energizes Bear Valley Line for PSPS.	1. Notify key staff and brief Field Operations staff on condition for situational awareness. 2. If Radford is energized, shift loads to Shay Line prior to de-energizing for PSPS. This should be done about 4 hours prior to the SCE de-energizing the line. 3. If needed, start up the BVPP to meet load demand. 4. If needed, instruct interruptible customers (Bear Mountain Resorts) to reduce load as needed to meet load demand. 5. Implement BVES EDRP for a partial loss of SCE supply lines.
SCE De-energizes Doble or Cushenberry **and** Bear Valley Lines for PSPS.	1. Notify key staff and brief Field Operations staff on condition for situational awareness. 2. Since the Doble and Cushenberry are capable of carrying the other's load, follow the procedure for "SCE De-energizes Bear Valley Line for PSPS" above. 3. Prepare for potentially losing all SCE supply lines into BVES service area. 4. Prepare for sustained BVPP operations and rolling blackouts. 5. Evaluate distribution circuit loads. 6. Implement BVES EDRP for a partial loss of SCE supply lines.
SCE De-energizes Doble **and** Cushenberry Lines for PSPS.	1. Notify key staff and brief Field Operations staff on condition for situational awareness. 2. Energize the Radford Line. 3. Four hours prior to SCE de-energizing the lines, per the Field Operations Supervisor's direction, shift as much of the load to the BVPP and Radford Line as follows: a. Open the Shay and Baldwin ARs. b. "Express" the Radford Line to Meadow Substation without overloading the Radford Line per Field Operations' switching order. c. Start BVPP, place enginators online, and increase load to within the combined capacity of the BVPP and Radford Line. d. Implement BVES EDRP for sustained loss of SCE supplies from Lucerne including "rolling blackout" procedures. 4. Prepare for sustained BVPP operations and rolling blackouts. 5. Frequently monitor distribution circuit loads.

7.3 BVES Directed PSPS

Bear Valley will invoke PSPS on bare conductor circuits when:

- When FPI is "High" and:
  - Wind speed 40 mph or more on bare conductor circuits
  - Wind speed 50 mph or more on bare conductor circuits with EPSS enabled
  - Wind speed 65 mph or more on covered conductor circuits

- When FPI is "Very High" or "Extreme" and:
  - Wind speed 35 mph or more on bare conductor circuits
  - Wind speed 45 mph or more on bare conductor circuits with EPSS enabled
  - Wind speed 65 mph or more on covered conductor circuits

Wind speed refers to actual or forecasted for sustained winds or wind gusts of 3 seconds or more.

Additionally, Field Operations may direct a PSPS if Wildfire Response Teams (Field Crews) determine that actual conditions are putting public safety at risk, such as:

- Blow-ins to the lines are likely or occurring;
- Wire slap is likely or occurring; and/or
- Other facility degradations are likely or occurring.

For covered conductor systems, the wind threshold may be increased to 65 mph, and a higher tolerance for blow-ins and wire slap is possible.

In evaluating the necessity to invoke a PSPS on its power lines, Bear Valley staff must also evaluate the following:

- **Fire Potential Index (FPI) and Ignition Risk:** FPI and ignition risk as determined from Technosylva's Wildfire Analyst Enterprise (WFA-E) models customized for Bear Valley's service area.
- **Forecasted and actual weather:** Sustained wind speed, wind gust strength, dryness (humidity), precipitation, etc.
- **Fuel inventory:** Buildup of ground cover vegetation, timber on the ground, thickness of forest, etc.
- **Dryness of fuel:** Dryness of dead vegetation, timber on the ground, etc.
- **System design limitations:** Installed bare conductor configuration, conventional expulsion fuses installed in the system, switches with limited protective and remote-control capabilities, etc.
- **T&D equipment failure or degradation:** Protective switch failure, loss of remote connectivity with protective devices, etc.
- **Vegetation buildup:** Excessive buildup of vegetation along power lines such that vegetation clearances are of concern when combined with high winds.

- **Missed or delayed inspection:** Detailed inspection or patrol per GO-95 missed or delayed, GO-174 inspection missed or delayed, other inspection deemed critical missed or delayed, etc.

- **Delayed correction of fire hazard inspection discrepancies:** Correction of "must be fixed before fire season" discrepancies, GO-95 discrepancies not corrected within required periodicity, etc.

- **Operational deviations from normal lineup:** Abnormal system lineup due to planned maintenance, system upgrades, equipment degradation, etc.

- **Degradation in situational awareness:** Failure or loss of connectivity with installed weather stations, loss of FPI model, loss of WFA-E application, loss of NFDRS (e.g., during Federal Government shutdown), loss of remote circuit monitoring, loss of HD Alert Camera coverage, etc.

- **Resource degradation:** Insufficient line crews and/or other key operation staff, loss of utility vehicles, etc.

Some of the degradations listed above may result in BVES management lowering the PSPS thresholds.

Therefore, considering the thresholds for invoking PSPS and the additional PSPS considerations listed above, in order to reduce the impact of BVES-directed PSPS events on its power lines, BVES is pursuing the following initiatives in the following categories:

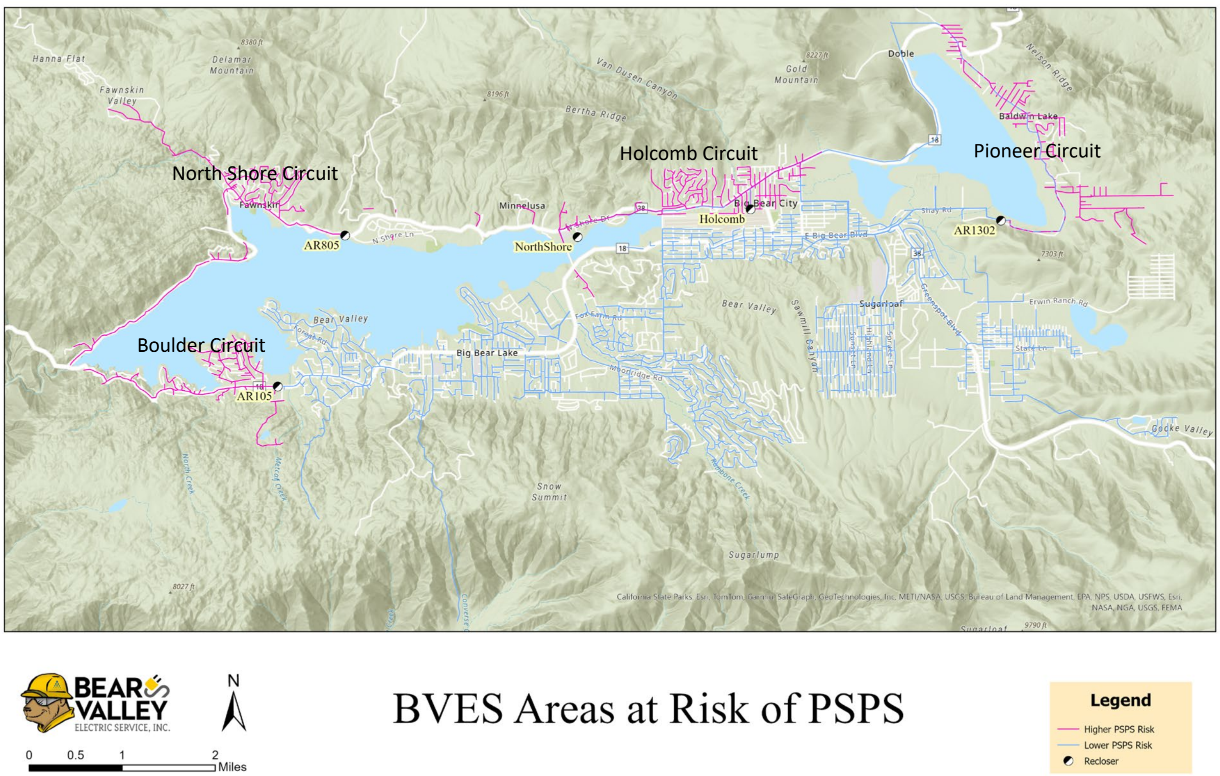
- Risk Methodology and Assessment (Section 5)
- Wildfire Mitigation Strategy Development (Section 6)
- Grid Design, Operations, and Maintenance (Section 8)
- Vegetation Management and Inspection (Section 9)
- Situational Awareness and Forecasting (Section 10)
- Emergency Preparedness and Community Outreach (Section 11)

Grid hardening initiatives such as Covered Conductor Replacement Project (Reconductor)(GD_1) and Covered Conductor Replacement Project (Pole Assessment) (GD_3) reduce the number of customers at risk of PSPS by elevating the PSPS thresholds on circuits that have been hardened. This reduces both scope and frequency. Most of Bear Valley's sub-transmission circuits have been hardened; therefore, the lower PSPS thresholds only exist on individual distribution circuits, which would affect smaller numbers of customers in localized areas served by the affected distribution circuit(s). As the number of circuit miles hardened increases, the frequency and scope of PSPS is reduced.

Additionally, Bear Valley is in the process of implementing an Enhance Power Line Safety Settings program (Equipment Settings to Reduce Wildfire Risk (GD_18)) during the period of this WMP. The impact of having EPSS enabled on bare conductor circuits is that the PSPS threshold increases.

In its 2023-2025 WMP, Bear Valley had identified the following circuits as having high PSPS risk: North Shore Circuit, Holcomb Circuit, Boulder Circuit, Lagonita Circuit, Clubview Circuit, Goldmine Circuit, Pioneer Circuit, Erwin Lake Circuit, and Radford Circuit. Through grid hardening initiatives, the Erwin Lake Circuit, Lagonita Circuit, Clubview Circuit, Goldmine Circuit, and Radford Circuit are no longer considered high PSPS risk. **Figure 7-6 BVES High Risk Areas for PSPS Consideration** identifies the current areas that are considered to have a higher likelihood of being under PSPS Consideration.

Figure 7-6 BVES High Risk Areas for PSPS Consideration



Grid hardening during the 2026-2028 period will result in the following circuits no longer being considered high PSPS risk: North Shore Circuit, Boulder Circuit, Holcomb Circuit and Pioneer Circuit greatly reducing the impact of PSPS events in the BVES service area.

The Switch and Field Device Automation (GD_8) initiative automates field switches and connects them to the SCADA control system. This allows switches to be operated remotely from the Distribution Management Center. The ability to operate field switches allows for segmenting circuits to only those areas that meet PSPS thresholds. Additionally, remote operation of switches allows Bear Valley to isolate and restore circuits or circuit segments more rapidly in PSPS scenarios. This initiative reduces the duration and scope of PSPS.

Equipment Settings to Reduce Wildfire Risk (GD_18) initiative will reduce the impact of PSPS by optimizing protective settings to reduce the risk of ignitions and, thereby, allow BVES to establish higher PSPS thresholds on bare wire circuits.

Asset inspection initiatives, which include Detailed Inspections (GD_22), Patrol Inspections (GD_23), UAV Thermography Inspections (GD_24), UAV HD Photography/Videography Inspections (GD_25), 3rd Party Ground Patrol Inspections (GD_26), and Intrusive Pole Inspections (GD_27), are being conducted to ensure the assumptions that go into establishing BVES's current PSPS thresholds are correct so that thresholds do not need to be reduced. This ensures PSPS impact does not increase.

By conducting asset maintenance as necessary and on schedule via the Equipment Maintenance and Repair (GD_15) and Traditional Overhead Hardening (GD_5) initiatives also ensures that assumptions that go into establishing BVES's current PSPS thresholds are correct so that thresholds do not need to be reduced. This ensures PSPS impact does not increase.

The Advanced Weather Monitoring and Weather Stations (SAF_1), Weather Forecasting (SAF_6) and Fire Potential Index (SAF_7) initiatives allow Bear Valley to more accurately forecast areas that may be at risk of exceeding PSPS thresholds with greater granularity, which results in fewer customers being potentially impacted. By having accurate situational awareness initiatives, Bear Valley is able to reduce duration, frequency and scope of PSPS.

Bear Valley's vegetation management initiatives to clear vegetation around power lines, which include Fall-in Mitigation and High-risk Species (VM_8), Clearance (VM_9), Pole Clearing (VM_10), Substation Defensible Space (VM_12) and Emergency Response Vegetation Management (VM_13), and vegetation management inspection initiatives, which include Detailed Inspections (VM_1), Patrol Inspections (VM_2), UAV HD Photography/Videography Inspections (VM_3), LiDAR Inspections (VM_4), 3rd Party Ground Patrol Inspections (VM_5), Substation Inspections (VM_6) and Satellite Imaging Inspections (VM_7) ensure the assumptions that go into establishing BVES's current PSPS thresholds are correct so that thresholds do not need to be reduced. This ensures that PSPS impact does not increase.

Risk Methodology and Assessment (RMA_1) initiative and Wildfire Mitigation Strategy Development (WMSD_1) are also important initiatives that allow BVES to evaluate PSPS risk and develop initiatives to reduce risk and PSPS impact.

As previously stated, Bear Valley has not experienced the environmental conditions that exceed its PSPS thresholds; therefore, Bear Valley has never invoked a PSPS on any of its circuits. However, Bear Valley has gained lessons learned from other utility-invoked PSPS events. These lessons include:

- It is important to place crews in the field to observe and communicate with decision makers the actual conditions in the field to allow for better judgement when invoking PSPS.
- During a PSPS event, it is efficient to have crews continuously patrol de-energized circuits and take action as soon as feasible and safe to correct any damage that the winds may have caused.
- Once a PSPS is invoked, as environmental conditions improve, it is efficient to place crews in the field on de-energized circuits at both ends and at mid-points if possible so that upon restoration, the field crews can conduct patrol inspections of the circuit in a methodical and efficient manner to allow quicker restoration of the circuit to service.
- Covered conductor grid hardening is effective at reducing the threat posed by blow-ins and wire slap and allow for increased PSPS thresholds.
- Automation of switches and substations speeds up PSPS restoration.
- Enhanced Power Line Safety Settings is effective at reducing the threat posed by blow-ins and wire slap and allow for increased PSPS thresholds.
- Installing sectionalizing devices is effective at reducing the scope of PSPS events to just the high-risk areas.

8. Grid Design, Operations, and Maintenance

8.1 Target

8.1.1 Qualitative Targets

Initiatives that have qualitative targets in the Grid Design, Operations, and Maintenance category are listed in **Table 8-1 Grid Design, Operation, and Maintenance Targets by Year** below.

8.1.2 Quantitative Targets

Initiatives that have quantitative targets in the Grid Design, Operations, and Maintenance category are listed in **Table 8-1 Grid Design, Operation, and Maintenance Targets by Year** below.

Table 8-1 Grid Design, Operation, and Maintenance Targets by Year

Initiative	Quantitative or Qualitative Target	Activity (Tracking ID #)	Previous Tracking ID (if applicable)	Target Unit	[2026] Target/Status	% Planned in HFTD for [2026]	% Planned in HFRA for [2026]	% Risk Reduction for [2026]	[2027] Total/Status	% Planned in HFTD for [2027]	% Planned in HFRA for [2027]	% Risk Reduction for [2027]	[2028] Total/Status	% Planned in HFTD for [2028]	% Planned in HFRA for [2028]	% Risk Reduction for [2028]	Three-year total	Section; Page number
Covered conductor installation	Quantitative	Covered Conductor Replacement Project (Reconductor) (GD_1)	GD_1	Circuit Miles Replaced	8	100%	100%	4.43%	10	100%	100%	5.54%	10	100%	100%	5.54%	28	8.2.1; p. 116
Undergrounding of electric lines and/or equipment	Quantitative	Minor Undergrounding Upgrades Projects (GD_2)	GD_3	Initiate Underground Projects as needed (% of Assigned Budget)	100%	100%	100%	3.12%	100%	100%	100%	3.12%	100%	100%	100%	3.12%	100%	8.2.2; p. 119
Distribution pole replacements and reinforcements	Quantitative	Covered Conductor Replacement Project (Pole Assessment) (GD_3)	GD_4	# of Poles Replaced or Reinforced	125	100%	100%	4.43%	150	100%	100%	5.54%	150	100%	100%	5.54%	425	8.2.3; p. 120
Distribution pole replacements and reinforcements	Quantitative	Evacuation Route Hardening Project (GD_4)	GD_6	# of Poles Hardened with Wire Mesh Wrap	500	100%	100%	5.56%	500	100%	100%	5.56%	500	100%	100%	5.56%	1500	8.2.3; p. 120
Traditional overhead hardening	Quantitative	Traditional overhead hardening (GD_5)	GD_8	% of Assigned Budget	100%	100%	100%	4.65%	100%	100%	100%	4.65%	100%	100%	100%	4.65%	100%	8.2.5; p. 124

Microgrids	Quantitative	Bear Valley Solar Energy Project (GD_6)	GD_10	% of Project Completed	N/A	N/A	N/A	N/A	100%	100%	100%	18.05%	N/A	N/A	N/A	N/A	100%	8.2.7; p. 126
Microgrids	Quantitative	Bear Valley Energy Storage Project (GD_7)	GD_11	% of Project Completed	N/A	N/A	N/A	N/A	100%	100%	100%	18.05%	N/A	N/A	N/A	N/A	100%	8.2.7; p. 126
Installation of system automation equipment	Quantitative	Switch and Field Device Automation (GD_8)	GD_12	# of switches connected to SCADA	10	100%	100%	4.41%	10	100%	100%	4.41%	10	100%	100%	4.41%	30	8.2.8; p. 128
Installation of system automation equipment	Quantitative	Capacitor Bank Upgrade Project (GD_9)	GD_14	# of units replaced	6	100%	100%	5.16%	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	6	8.2.8; p. 128
Installation of system automation equipment	Quantitative	Fuse TripSaver Automation (GD_10)	GD_15	# of TripSavers connected to SCADA	10	100%	100%	3.68%	10	100%	100%	3.68%	10	100%	100%	3.68%	30	8.2.8; p. 128
Other grid topology improvements to minimize risk of ignitions	Quantitative	Non-Exempt Surge Arrester Replacement (GD_11)		# of Non-exempt surge arresters replaced	58	100%	100%	3.46%	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	58	8.2.10; p. 133
Other grid topology improvements to minimize risk of ignitions	Quantitative	Tree Attachment Removal Project (GD_12)	GD_19	# of Tree Attachments Removed	100	100%	100%	5.56%	100	100%	100%	5.56%	45	100%	100%	2.50%	245	8.2.10; p. 133
Other technologies and systems not listed above	Quantitative	Safety and Technical Upgrades to Lake Substation (GD_13)	GD_23	% of Project Completed	50%	100%	100%	0	50%	100%	100%	4.65%	N/A	N/A	N/A	N/A	100%	8.2.12; p. 136

Other technologies and systems not listed above	Quantitative	Partial Safety and Technical Upgrades to Village Substation (GD_14)	GD_24	% of Project Completed	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	100%	100%	100%	4.65%	100%	8.2.12; p. 136
Equipment maintenance and repair	Quantitative	Equipment maintenance and repair (GD_15)	GD_33	% of Assigned Budget	100%	100%	100%	4.34%	100%	100%	100%	4.34%	100%	100%	100%	4.34%	100%	8.4.1; p. 147
Quality assurance / quality control	Quantitative	Asset Quality assurance / quality control (GD_16)	GD_35	Number of Asset QCs on WMP Work	20	100%	100%	4.48%	20	100%	100%	4.48%	20	100%	100%	4.48%	60	8.5;p.155
Work orders	Quantitative	Asset Open work orders (GD_17)	GD_36	90% or more of work orders compelted on schedule for the year	90%	100%	100%	3.43%	90%	100%	100%	3.43%	90%	100%	100%	3.43%	90%	8.6;p.162
Equipment Settings to Reduce Wildfire Risk	Quantitative	Equipment Settings to Reduce Wildfire Risk (GD_18)	GD_37	% of EPSS Plan Achieved	100%	100%	100%	8.51%	100%	100%	100%	8.51%	100%	100%	100%	8.51%	100%	8.7.1; p. 164
Grid Response Procedures and Notifications	Qualitative	Grid Response Procedures and Notifications (GD_19)	GD_38	Review Grid Procedures and Update Annually	Performed annually	100%	100%	3.12%	Performed annually	100%	100%	3.12%	Performed annually	100%	100%	3.12%	N/A	8.7.2; p. 169
Personnel Work Procedures and Training in Conditions of Elevated Fire Risk	Qualitative	Personnel Work Procedures and Training in Conditions of Elevated Fire Risk (GD_20)	GD_20	Conduct Training and Review Procdures for Elevated Fire Risk Conditions	Performed annually	100%	100%	3.12%	Performed annually	100%	100%	3.12%	Performed annually	100%	100%	3.12%	N/A	8.7.3; p. 171
Workforce Planning	Qualitative	Asset Workforce Planning (GD_21)	GD_21	Evaluate annually workforce training and adequacy	Performed annually	100%	100%	4.65%	Performed annually	100%	100%	4.65%	Performed annually	100%	100%	4.65%	N/A	8.8; p. 172
Asset Inspection	Quantitative	Detail Inspection (GD_22)	GD_22	Circuit Miles Inspected	55	100%	100%	4.65%	55	100%	100%	4.65%	55	100%	100%	4.65%	165	8.3.1; p. 141

Asset Inspection	Quantitative	Patrol Inspections (GD_23)	GD_23	Circuit Miles Inspected	205	100%	100%	4.65%	205	100%	100%	4.65%	205	100%	100%	4.65%	615	8.3.2; p. 142
Asset Inspection	Quantitative	UAV Thermography Inspections (GD_24)	GD_24	Circuit Miles Inspected	205	100%	100%	4.65%	205	100%	100%	4.65%	205	100%	100%	4.65%	615	8.3.3; p. 143
Asset Inspection		UAV HD Photography/Videography Inspections (GD_25)	GD_25	Circuit Miles Inspected	205	100%	100%	4.65%	205	100%	100%	4.65%	205	100%	100%	4.65%	615	8.3.4; p. 143
Asset Inspection	Quantitative	Third-Party Ground Patrol Inspections (GD_26	GD_26	Circuit Miles Inspected	205	100%	100%	4.65%	205	100%	100%	4.65%	205	100%	100%	4.65%	615	8.3.5; p. 145
Asset Inspection	Quantitative	Intrusive Pole Inspections (GD_27)	GD_27	# of Poles Tested	850	100%	100%	4.65%	850	100%	100%	4.65%	850	100%	100%	4.65%	2550	8.3.6; p. 146
Asset Inspection	Quantitative	Substation inspections (GD_28)	GD_28	# of Substations Inspected	144	100%	100%	4.65%	144	100%	100%	4.65%	144	100%	100%	4.65%	432	8.3.7; p. 147
Transmission pole/tower replacements and reinforcements	N/A	BVES currently does not have any projects under this initiative	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	8.2.4; p. 124
Emerging grid hardening technology installations and pilots	N/A	BVES currently does not have any projects under this initiative	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	8.2.6; p. 126
Line removals (in HFTD)	N/A	BVES currently does not have any projects under this initiative	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	8.2.9; p. 133

Other grid topology improvements to mitigate or reduce PSPS events	N/A	BVES currently does not have any projects under this initiative	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	8.2.11; p. 135

8.2 Grid Design and System Hardening

8.2.1 Covered Conductor Installation (Tracking ID: GD_1) (Utility Initiative Name: Covered Conductor Replacement Project (Reconductor)

8.2.1.1 Overview

Covered conductors are any conductors (wires) covered by layers of insulation. Vendors designed these wires to withstand incidental contact with vegetation or other debris. Bare wires were historically used to provide a reliable, cost-effective solution for delivering energy to customers. BVES performed covered conductor pilot programs under previous WMPs that demonstrated reduced fire risk and no adverse impacts on reliability. Covered conductors is an accepted practice to eliminate vegetation and debris contact as well as wire slap to reduce ignitions that could lead to wildfires. The Covered Conductor Replacement Project raises the threshold for PSPS events to higher wind speeds compared to bare conductor hardening. While Bear Valley's entire service area is in HFTD Tiers 2 and 3, Bear Valley is pursuing replacing bare conductors with covered conductors by prioritizing the higher risk areas as discussed in Section 6.

Undergrounding the 34 kV system would be the only other technically acceptable alternative. However, the cost would be over 10 times that of the covered wire replacement project. Additionally, certain areas present significant challenges to undergrounding the overhead system. Therefore, Covered Conductor Replacement Project yields a more attractive RSE. Thus, BVES decided to replace bare conductors with covered conductors on all sub-transmission lines (34.5 kV) and to replace all bare conductor distribution lines in the higher risk areas within the service area with covered conductors. The Covered Conductors Replacement Project is prioritized based on higher risk circuits to maximize the risk reduction. These high-risk circuits (or segments) were determined based on the FireSight model. During the period of this WMP, Bear Valley intends to replace bare conductors with covered conductors as follows:

- Holcomb 4kV (North Shore Big Bear City Area): 4.5 circuit miles planned for 2026.
- Boulder 4kV (Boulder Bay Area): 3.5 circuit miles planned for 2026.
- North Shore 4kV (Fawnskin Area): 2 circuit miles planned for 2027.
- Pioneer 4kV (Baldwin Lake Area): 8 circuit miles planned for 2027.
- North Shore 4kV (Fawnskin Area): 4 circuit miles planned for 2028.
- Boulder 4kV (Boulder Bay Area): 3 circuit miles planned for 2028.
- Clubview 4kV (Moonridge Area): 3 circuit miles planned for 2028.

8.2.1.2 Impact of the activity on wildfire risk

This initiative intends to reduce potential ignition events by installing covered conductors; thereby significantly reducing surface areas where vegetation and other objects may make contact with live electrical surfaces, which could result in ignitions. Additionally, covered conductors reduce ignition risk by eliminating the potential for wire slap. Based on the CPUC ignition database (2014 to 2023 data) of all utility-caused ignitions in the HFTD, the following was recorded:

- Bare conductor contact with vegetation resulted approximately 23 percent (1,291 instances) of all utility-caused ignitions in the HFTD.
- Bare conductor contact with other objects resulted approximately 32 percent (1,807 instances) of all utility-caused ignitions in the HFTD.
- Bare conductor wire-to-wire contact (wire slap) resulted approximately 1.4 percent (79 instances) of all utility-caused ignitions in the HFTD.

Risk reduction in the HFTD due to covered conductor installation is expected to be 4.43% in 2026 (8 circuit miles), 5.54% in 2027 (10 circuit miles), and 5.54% in 2028 (10 circuit miles) as determined by the SMJU 7x7 Risk Based Decision Making Model. As of December 31, 2024, Bear Valley had accomplished the following in the Covered Conductor Replacement Project (Reconductor):

- At the end of 2024, 16.8 percent of the sub-transmission system was bare conductors. At the start of 2019, it was 97.0 percent bare wire. Replaced 23.9 circuit miles of sub-transmission bare wire with molded covered conductor.
- At the end of 2024, 58.7 percent of the distribution system was bare conductors. At the start of 2019, it was 77.4 percent bare wire. Replaced 43.9 circuit miles of distribution bare wire with molded covered conductor.

By the end of 2028, the sub-transmission system will have no bare conductors and the distribution system will be 47 percent bare conductors (down from 58.7 percent). Stated in other words, the sub-transmission system will have near zero likelihood of ignition due to contact with vegetation or other objects and wire slap and the probability of an ignition on the distribution system due to contact with vegetation or other objects and wire slap will be further reduced by over 50 percent.

8.2.1.3 Impact of the activity on outage program risk

As discussed above, replacing bare conductors with covered conductors reduces the probability of a circuit having contact due to vegetation, other objects, and wire slap. Over the last nine years, contact with vegetation, other objects, and wire slap accounted for 184.4 minutes of System Average Interruption Duration Index (SAIDI). Replacing 28 circuit miles of bare conductors with covered conductors will result in a reduction of 12 percent of bare conductors. Therefore, outages due to contact are expected to decrease by about 22.1 minutes of SAIDI.

When selecting areas to harden, BVES considers and evaluates the hardened status of upstream circuits/segments/spans to determine the impact of the activity on reliability risk as well as PSPS risk. Bear Valley's circuits are relatively small. Where circuits can be powered by alternate sources (e.g., tying two circuits through switching), BVES uses this method to mitigate unhardened segments. Where circuits are radial, BVES will generally harden the remote ends first, since these are generally also the higher risk segments. Radial circuits generally extend into remote areas and the remote ends are generally in the heavier vegetation areas; thus have higher risk both of ignitions and outages due to contact.

Installing covered conductors increases the PSPS wind threshold by approximately 85 percent, thereby greatly reducing the likelihood of PSPS to very remote. In fact, based on 10 years of past wind data on high-risk days, winds (sustained or gusts) have not come close to the threshold for covered conductor circuits.

It is too early to evaluate empirically how the covered conductor program has reduced overall outages. In 2024, no sub-transmission circuit experienced an outage due to contact and only 30% of the sub-transmission system was bare conductors. Furthermore, no area where covered wire has been installed has ever experienced an outage due to contact at Bear Valley. BVES will continue to monitor this closely but indications are that outages due to contact will be reduced over time as covered conductors replace bare conductors.

8.2.1.4 Updates to the activity

As covered conductors become a larger part of the system, performance indicators that impact the efficacy of this mitigation will continue to be monitored and measured, including the measured effectiveness (number of faults per operating year per mile relative to the unhardened system averages) and the cost per mile. BVES will also continue to participate in the joint IOU covered conductor work streams to further develop the estimated and calculated effectiveness of covered conductor.

8.2.1.5 Compatible activities:

The Covered Conductor Replacement Project (Pole Assessment)(GD_3) activity is mostly achieved in conjunction with this initiative. Before covered conductor is installed, each affected pole is fully assessed and those not meeting GO-95 requirements are replaced or remediated. Additionally, most of the objectives of the Traditional Overhead Hardening (GD_5) are achieved in this initiative.

8.2.2 Undergrounding of Electric Lines and/or Equipment (Tracking ID: GD_2) (Utility Initiative Name: Minor Undergrounding Upgrades Projects)

8.2.2.1 Overview of the activity

BVES currently does not have any major undergrounding projects planned. This activity addresses the utility actions taken to underground (UG) electrical lines and equipment in accordance with GO 128. BVES conducts small undergrounding projects for new developments and services and minor upgrades to existing facilities. When feasible, BVES works to install UG facilities for new developments and services to reduce the number of overhead facilities and therefore the risk those facilities pose to wildfire. BVES also conducts small upgrades to existing UG facilities so that service is safe, reliable, and of high quality.

The main alternative mitigation to undergrounding facilities is to convert bare conductor overhead facilities to covered conductor overhead facilities. There are several advantages in selecting covered conductors over undergrounding that include:

- Ease of construction: Bear Valley's service area is very rocky and has significant tree roots in the terrain making installation of underground facilities very challenging; whereas replacing bare conductors has less intrusive construction with respect to the terrain (limited to some pole replacements).
- Less complicated planning: Converting overhead facilities to underground facilities requires significant planning and construction design; whereas replacing bare conductors with covered conductors simply requires assessing existing pole structures and replacing some poles to accommodate the covered conductors.
- Less cost: Undergrounding in Bear Valley's difficult terrain is significantly more expensive that installing covered conductors. Undergrounding costs can reach 5 to 10 times the cost of overhead construction.
- Permitting ease: Converting overhead facilities to underground facilities in the Bear Valley service area would require significant permitting with various permitting entities including the U.S. Forest Service, Caltrans, California Department of Fish and Wildlife, California Department of Water Resources, City of Big Bear Lake and County of San Bernardino; whereas replacing bare conductors with covered conductors without changing the existing footprint of the facilities reduces the permitting requirements significantly.
- Less time to reduce risk: By selecting to replace bare conductors with covered conductors instead of converting overhead facilities to underground facilities, Bear Valley has significantly reduced the time to achieve significant ignition and PSPS risk reduction. Just the planning, design and permitting for undergrounding can take 3-5 years before an underground trench can be dug out. Furthermore, the pace of reconductoring overhead facilities is much faster than the pace of installing underground facilities.

The major advantage of covered conductors is that they cost significantly less per circuit mile than UG facilities yet the marginal gain in risk reduction by utilizing UG instead of covered conductors is not nearly as significant.

8.2.2.2 Impact of the activity on wildfire risk

The minor UG projects that BVES engages in are generally driven by the customer or local government and are generally new facilities; therefore, it is difficult to prioritize them by wildfire risk. However, as noted before, BVES's entire service area is in HFTD Tiers 2 and 3 so any UG has a significant wildfire risk reduction benefit.

8.2.2.3 Impact of the activity on outage program risk

The minor UG projects that BVES engages will not have a significant impact on outage program risk due to their small size. It should be noted that outages on underground facilities at BVES are very infrequent. In fact, in the last three years, Bear Valley has not had an outage on UG facilities.

8.2.2.4 Updates to the activity

There are no immediate plans for large-scale undergrounding projects in the 2026 to 2028 period. BVES will continue to conduct small UG projects driven by new developments and local government during this period.

BVES is aware of and following the major undergrounding initiatives at the larger IOUs. BVES will continue to reassess the need of potential undergrounding projects and will continue to exchange information with the other utilities on the advantages and disadvantages of UG and covered conductors through working groups. BVES will watch carefully for any advances in UG installation, especially those that reduce the price point while maintaining GO 128 specifications and public safety standards.

8.2.2.5 Compatible activities

The minor UG projects that BVES engages in are generally driven by the customer or local government and are generally new facilities; therefore, it is difficult coordinate this initiative with other WMP activities.

8.2.3 Distribution Pole Replacements and Reinforcements Project (Tracking ID: GD_3 and GD_4)

BVES has two initiatives in this activity. They are:

- (Tracking ID: GD_3) Utility Initiative Name: Covered Conductor Replacement Project (Pole Assessment))
- (Tracking ID: GD_4) Utility Initiative Name: Evacuation Route Hardening Project

8.2.3.1 Covered Conductor Replacement Project (Pole Assessment GD_3)

Overview of the activity

Bear Valley has an ongoing project to proactively assess and remediate noncompliant distribution poles. Due to synergy with the Covered Conductor Replacement Project (Reconductor)(GD_1) initiative, for the period of this WMP, this initiative is conducted together. Before covered conductor is installed, each affected pole is fully assessed and those not meeting GO 95 requirements are replaced or remediated. GO 95 Rule 43.1 requires BVES to design, build, and maintain their overhead facilities to withstand foreseeable fire and wind conditions in the service territory.

Poles that are not compliant with GO 95 safety factors are identified, and the appropriate remediation will be designed and implemented. Depending on the nature and extent of the noncompliance, the remediation will require either repair (e.g., the installation or modification of guy wires) or complete replacement of the pole, including removal and reinstallation of all attachments, all within the time frames required by GO 95. GO 95 is aimed at the safety of personnel, the public, and preserving the reliability of the power grid. Risk is significantly reduced when poles are brought into compliance with laws directed at preserving safety and reliability. In coordination with the Covered Conductor Replacement Project (Reconductor)(GD_1) initiative, Bear Valley expects to replace or repair poles in the distribution system as follows:

- 2026: 125 poles
- 2027: 150 poles
- 2028: 150 poles

The work areas for Covered Conductor Replacement Project (Reconductor)(GD_1) initiative are risk-based; therefore, this initiative will target the same high risk work areas.

Impact of the activity on wildfire risk

Meeting or exceeding the mandates of GO 95 is critical to mitigate wildfires. Noncompliant poles are a fire risk. Since the entire BVES service area is in HFTD Tiers 2 and 3, any pole failure is considered a high fire risk. Additionally, BVES is 3,000 feet above sea level and is subject to heavy loading requirements. Overhead distribution lines are exposed to severe weather including heavy snow, ice, and high winds. Risk reduction in the HFTD due to covered conductor installation is expected to be 4.43% in 2026 (8 circuit miles/125 poles), 5.54% in 2027 (10 circuit miles/150 poles), and 5.54% in 2028 (10 circuit miles/150 poles) as determined by the SMJU 7x7 Risk Based Decision Making Model.

Impact of the activity on outage program risk

Without this initiative, the impact on outage program risk would be significant. Because Bear Valley Bear Valley constructs its facilities to the “Heavy Loading” standards in GO

95, its structures are very strong and capable of high winds. It is rare to have an outage due to structure failure. If a structure fails, it is always driven by an external cause such as a car-hit-pole for example or a large tree falling into the facilities during a major winter storm. Distribution pole replacements and reinforcements allows Bear Valley to establish PSPS thresholds that are primarily directed at the threat of "blow-ins" rather than concern for structural integrity of the overhead facilities.

Updates to the activity

Bear Valley will apply lessons learned throughout the progression of this initiative. Where possible, BVES will look for synergies between initiatives such as covered wire installation and pole loading assessment, infrastructure hardening, and replacement programs to maximize the risk benefit associated with each project.

BVES participates in the joint utilities covered wire working group and will continue to exchange information regarding pole replacements associated with covered wire installation. Additionally, BVES will participate in T&D conferences and review current T&D literature and periodicals to gain the latest information on pole replacement practices.

Compatible activities

The Covered Conductor Replacement Project (Reconductor)(GD_1) activity is mostly achieved in conjunction with this initiative. Before covered conductor is installed, each affected pole is fully assessed and those not meeting GO-95 requirements are replaced or remediated. Additionally, most of the objectives of the Traditional Overhead Hardening (GD_5) are achieved in this initiative.

8.2.3.2 Evacuation Route Hardening Project (GD_4)

Overview of the activity

The Evacuation Route Hardening Project aims to build upon the work that Bear Valley previously accomplished in the area of hardening evacuation routes. In 2020 and 2021, Bear Valley completed a pilot program to investigate the optimal means to harden evacuation routes and developed the following plan and policy:

- Install the wire mesh protective coating on 812 wood poles along the primary evacuation routes as soon as feasible over a 2-year period. This was completed in 2021 and 2022.
- Install the wire mesh protective coating on poles along secondary roads leading to the primary evacuation routes at a rate of about 500 poles per year. Pole hardening would be prioritized for the higher population density areas and high fire risk areas.
- Establish a policy that whenever a pole is replaced or a new pole is installed on a primary evacuation route or a secondary road leading to a primary evacuation route, the replacement would be a fire resistance composite or LWS pole.

- Establish a policy that whenever any pole is replaced or a new pole is installed that is a wood pole, the installation work will include installing the wire mesh wrap on the pole.

This project is aimed at hardening electrical assets along secondary roads that lead to the primary evacuation routes. As noted above, the primary evacuation routes have already been hardened. The hardening of BVES electrical assets (poles, wires, equipment) along the evacuation routes and secondary roads that lead to primary evacuation routes is important to ensure they do not fail during a wildfire, which would limit mobility along the evacuation routes required to safely perform an evacuation. Lessons learned from past wildfires indicate hardening of utility assets along evacuation routes is critical to public safety for the following reasons:

- To allow the safe evacuation of the public in the event of a wildfire; and
- To allow the mobility for First Responders to move assets in and out of the wildfire areas to allow them to actively fight the wildfire to save lives, protect property, and minimize environmental damage.

This initiative will install wire mesh on 500 wood poles per each year of this WMP.

Impact of the activity on wildfire risk:

The primary objective of this evacuation route hardening program is not to reduce the risk of ignition resulting in a wildfire. Rather, the primary objective of the program is to add resiliency and safety to evacuation routes during an evacuation due to a wildfire or other emergencies. Hardening of BVES electrical assets (poles, wires, equipment) along the evacuation routes is important to ensure they do not fail during a wildfire which would limit mobility along the evacuation routes required to safely perform the evacuation. Additionally, routes must also be unencumbered to allow the movement of first responders and their equipment during a wildfire. This initiative will reduce wildfire risk by 5.56 percent per year as determined by the SMJU 7x7 Risk Based Decision Making Model.

Impact of the activity on outage program risk

Since the primary objective of this evacuation route hardening is to add resiliency and safety of the evacuation routes, the project does not directly address the impact to outage risk nor does it impact PSPS risk.

Updates to the activity

BVES will continue its effort across its service area to upgrade and replace poles. BVES has already achieved hardening with a significant portion of its poles in its service area are under 10 years old. BVES has a goal to install wire mesh wrap on approximately 500 poles per year to harden the secondary evacuation routes that lead to the primary evacuation routes.

Compatible activities:

The Covered Conductor Replacement Project (Reconductor) (GD_1), Covered Conductor Replacement Project (Pole Assessment) (GD_3), and the Traditional Overhead Hardening (GD_5) initiatives are compatible with this initiative. When work is planned under these initiatives, wire mesh can be installed on wood poles that do not have to be replaced or are repaired and the policy of using fire resistant poles is applied to any pole replacements as feasible.

8.2.4 Transmission Pole/Tower Replacements and Reinforcements

(Tracking ID: None assigned)

Bear Valley does not own or operate any transmission assets; therefore, Bear Valley does not undertake this activity.

8.2.5 Traditional Overhead Hardening (Tracking ID: GD_5)(Utility Initiative Name: Traditional Overhead Hardening)

8.2.5.1 Overview of the activity:

Bear Valley operates and maintains 205.5 circuit miles of overhead facilities in the HFTD. Because all of Bear Valley's facilities are above 3,000 feet, Bear Valley constructs its facilities to the "Heavy Loading" standards in GO 95. Most of the work that aligns with this initiative is accomplished in the Covered Conductor Replacement Project (Reconductor)(GD_1) and Covered Conductor Replacement Project (Pole Assessment)(GD_3) initiatives. All poles involved in the Covered Conductor Replacement Project are fully assessed to ensure they can accommodate the covered conductors per GO 95 requirements. Poles that are not compliant with GO 95 safety factors are identified and remediated appropriately. Depending on the nature and extent of the noncompliance, the remediation will require either repair (e.g., the installation or modification of guy wires) or complete replacement of the pole, including removal and reinstallation of all attachments, all within the time frames required by GO 95. GO 95 is aimed at the safety of personnel, the public, and preserving the reliability of the power grid. Risk is significantly reduced when poles are brought into compliance with laws directed at preserving safety and reliability.

Bear Valley's periodic asset inspection programs (Detailed, Patrol, UAV Thermography, UAV HD Photography/Videography, 3rd Party Ground Patrol, and Intrusive Pole Inspections) results in findings where poles must be repaired or replaced depending on the nature of the inspection finding within the timeframes required by GO 95.

Finally, traditional overhead hardening may be driven by other actions such as by local government requiring BVES to relocate facilities under its franchise agreement due to road modifications, corrective maintenance due to third party issues such as car-hit-pole accidents, and corrective maintenance due to storm damage.

8.2.5.2 Impact of the activity on wildfire risk:

This initiative reduces the risk of ignitions by reducing the likelihood of a structure failure, which could cause downed lines leading to a possible ignition source. Maintaining overhead facilities to the specifications of the "Heavy Loading" district per GO-95 is a wildfire risk control that contributes to a risk reduction equivalent to 4.65% as determined by the SMJU 7x7 Risk Based Decision Making Model.

8.2.5.3 Impact of the activity on outage program risk:

Without this initiative, the impact on outage program risk would be significant. Because Bear Valley constructs its facilities to the "Heavy Loading" standards in GO 95, its structures are very strong and capable of high winds. It is rare to have an outage due to structure failure. If a structure fails, it is always driven by an external cause such as a car-hit-pole for example or a large tree falling into the facilities during a major winter storm. Traditional overhead hardening allows Bear Valley to establish PSPS thresholds that are primarily directed at the threat of "blow-ins" rather than concern for structural integrity of the overhead facilities.

8.2.5.4 Updates to the Activity

Bear Valley will apply lessons learned throughout the progression of this initiative. Where possible, BVES will look for synergies between initiatives such as covered conductor installation and pole loading assessment, infrastructure hardening, and replacement programs to maximize the risk benefit associated with each project.

BVES participates in the joint utilities covered conductors working group and will continue to exchange information regarding pole replacements associated with covered wire installation. Additionally, BVES will participate in T&D conferences and review current T&D literature and periodicals to gain the latest information on pole replacement practices.

As part of the covered conductor replacement project, cross-arms and other pole mounted equipment are replaced when installing covered conductors.

8.2.5.5 Compatible Activities

As discussed above, much of the objectives of traditional overhead hardening are achieved via the Covered Conductor Replacement Project (Reconductor) (GD_1) and Covered Conductor Replacement Project (Pole Assessment)(GD_3) initiatives. Before covered conductor is installed, each affected pole is fully assessed and those not meeting GO 95 requirements are replaced or repaired.

8.2.6 Emerging Grid Hardening Technology Installations and Pilots (Tracking ID: None assigned)

Bear Valley currently does have any activities in this area. In the WMP Joint IOU workshops, BVES has participated in discussions on new technologies such as Distribution Fault Anticipation (DFA), Early Fault Detection (EFD), and Rapid Earth Fault Current Limiters (REFCL). It was determined that REFCL applies to grounded system only, and BVES 34KV sub-transmission is a delta system. Therefore, REFCL is not compatible with the BVES grid system.

Bear Valley has some initiatives in the Situational Awareness and Forecasting that involve emerging technologies. They are the Online Diagnostic System (SAF_3) discussed in Section 10.3 and Autonomous Monitoring of Power Line Infrastructure (SAF_4) discussed in Section 10.4.

8.2.7 Microgrids (Tracking ID: GD_6 and GD_7)

BVES has two initiatives in this activity. They are:

- (Tracking ID: GD_6) Utility Initiative Name: Bear Valley Solar Energy Project
- (Tracking ID: GD_7) Utility Initiative Name: Bear Valley Energy Storage Project

8.2.7.1 Bear Valley Solar Energy Project (GD_6)

Overview of the activity:

Bear Valley is developing a Solar Energy Project that consists of 5 MW alternating current single-axis tracker solar generation facility, to be constructed on a 21-acre site within the BVES service territory. This system will directly feed the distribution system benefiting all customers. On May 17, 2024, BVES filed an application (A.24-05-020) with the CPUC to gain authorization for the project. Additionally, in July 2024 BVES began the permitting process with the County of San Bernardino for the facility and in February 2025, BVES filed an Initial Study pursuant to San Bernardino County Guidelines under Ordinance 3040 and Section 15063 of the State California Environmental Quality Act (CEQA) Guidelines for a Conditional Use Permit to allow for the construction and operation of a 5-megawatt alternating current solar photovoltaic facility and a General Plan Amendment to rezone the Project site from Residential Single - 1 acre minimum to Rural Living or similar zone. The County of San Bernardino Land Use Services Department is the Lead Agency in this filing. Once BVES gains CPUC approval and County of San Bernardino approval, Bear Valley's developer, EDF Renewables Distributed Solutions, Inc. (EDF), will procure materials and construct the project. Based on application and permitting approval timelines, procurement timelines, and construction timelines, Bear Valley anticipates the project will be completed by the end of 2027.

Impact of the activity on wildfire risk:

The proposed solar project enhances safety, reliability, and quality of service. The project is designed to mitigate the potential of ignitions by removing the need to expand sub-transmission supply lines to Bear Valley's service area as demand increases, which may cause wildfires with catastrophic loss of life and enormous loss of property.

Impact of the activity on outage program risk:

The solar project will reduce the impact of loss of supplies from the Southern California Edison (SCE) power lines that serve Bear Valley. From 2022 to 2024, loss of supplies from SCE resulted in a cumulative SAIDI of 77.9 minutes. Had the solar project been in operation, it is estimated that the loss of supplies from SCE for the same period would have resulted in a cumulative SAIDI of 1.4 minutes, which is a significant improvement to reliability.

This project significantly reduces the impact of SCE initiating a PSPS event affecting the supply power lines to Bear Valley. One of the objectives of the solar project is to minimize the impact of the loss of all SCE energy imports to the BVES service area due to a SCE-directed PSPS of the SCE supply lines to BVES. BVES energy imports from SCE are subject to PSPS and while these lines may be required to be de-energized by SCE, the BVES service area may not require PSPS. The PSPS risk reduction is expected to be 18.05 percent as determined by the SMJU 7x7 Risk Based Decision Making Model.

Updates to the activity

Bear Valley is in the application and permitting process for this project. If this proposed solar project along with the proposed battery project, Bear Valley Energy Storage Project (GD_7), are approved, BVES will be able to internally supply energy to all critical infrastructure and its customers by utilizing its existing peaking power plant (8.4 MW), along with the solar and battery facilities; thereby, minimizing the impact of any SCE PSPS event affecting Bear Valley's supply power lines.

Compatible activities

This initiative is compatible with the Bear Valley Energy Storage Project (GD_7), which will operate together.

8.2.7.2 Bear Valley Energy Storage Project (GD_7)

Overview of the activity

Bear Valley is developing a Battery Storage Project that consists of 5 MW/20 MWh Lithium Iron Phosphate (LFP) utility-grade battery in its service area. This project will complement the Bear Valley Solar Energy Project (GD_6). On May 17, 2024, BVES filed an application (A.24-05-020) with the CPUC to gain authorization for the project. The project will fall under the permitting authority of the City of Big Bear Lake and its location is Parcel zoned C-5: Commercial-Industrial "Electricity Substation; Small Generation Plant" = Permitted Use. Once BVES gains CPUC approval, Bear Valley's developer, EDF Renewables Distributed Solutions, Inc. (EDF), will procure materials and construct the project. Based on application approval timelines, procurement timelines, and construction timelines, Bear Valley anticipates the project will be completed by the end of 2027.

Impact of the activity on wildfire risk

The proposed battery project enhances safety, reliability, and quality of service. The project is designed to mitigate the potential of ignitions by removing the need to expand sub-transmission supply lines to Bear Valley's service area as demand increases, which may cause wildfires with catastrophic loss of life and enormous loss of property.

Impact of the activity on outage program risk:

The battery project will reduce the impact of loss of supplies from the Southern California Edison (SCE) power lines that serve Bear Valley. From 2022 to 2024, loss of supplies from SCE resulted in a cumulative SAIDI of 77.9 minutes. Had the battery project been in operation, it is estimated that the loss of supplies from SCE for the same period would have resulted in a cumulative SAIDI of 28.8 minutes, which is a significant improvement to reliability.

This project significantly reduces the impact of SCE initiating a PSPS event affecting the supply power lines to Bear Valley. One of the objectives of the storage project is to minimize the impact of the loss of all SCE energy imports to the BVES service area due to a SCE-directed PSPS of the SCE supply lines to BVES. BVES energy imports from SCE are subject to PSPS and while these lines may be required to be de-energized by SCE, the BVES service area may not require PSPS. The PSPS risk reduction is expected to be 18.05 percent as determined by the SMJU 7x7 Risk Based Decision Making Model.

Updates to the activity

Bear Valley is in the application process for this project. If this proposed battery project along with the proposed solar project, Bear Valley Solar Energy Project (GD_6), are approved, BVES will be able to internally supply energy to all critical infrastructure and its customers by utilizing its existing peaking power plant (8.4 MW), along with the solar and battery facilities; thereby, minimizing the impact of any SCE PSPS event affecting Bear Valley's supply power lines.

Compatible activities

This initiative is compatible with the Bear Valley Solar Energy Project (GD_6), which will operate together.

8.2.8 Installation of System Automation Equipment (Tracking ID: GD_8, GD_9, and GD_10)

BVES has three initiatives in this activity. They are:

- (Tracking ID: GD_8) Utility Initiative Name: Switch and Field Device Automation

- (Tracking ID: GD_9) Utility Initiative Name: Capacitor Bank Upgrade Project
- (Tracking ID: GD_10) Utility Initiative Name: Fuse TripSaver Automation

8.2.8.1 Switch and Field Device Automation (GD_8)

Overview of the activity

This project aims to automate and connect to Bear Valley's SCADA network 30 sub-transmission (34 kV) switches and distribution switches over the 3 years of this WMP (10 per year) in order to allow remote real-time monitoring, reporting, and documenting key switch parameters and enable remote operation of the switches. The project involves the following elements: installing SCADA enabled control equipment, enhancing telemetry, and creating the capability to collect and modify settings remotely. This project will establish a robust and secure IP communications network across the sub-transmission and distribution systems to fully enable monitoring and control of critical switches throughout the sub-transmission and distribution systems. Critical switches in the system will be automated and connected to SCADA in a phased approach. Connectivity to SCADA will be via the BVES service area fiber optic network and in some cases via radio/cellular data transfer equipment. Automated switches will have battery backup power to permit remote connectivity and operation on a complete loss of power.

The Switch and Field Device Automation Project will have significant public safety, reliability, resiliency and quality of service benefits, including the following:

- System will monitor, report, and document key parameters on field switches that may indicate impending catastrophic equipment failures that may cause ignitions leading to wildfires, allowing Bear Valley to evaluate the situation, to develop and plan appropriate technical solutions, and then take the directed corrective action.
- System will monitor, report via alarms, and document key parameters on field switches that indicate a catastrophic equipment failure or fault has occurred that may cause ignitions leading to wildfires and allow immediate action to be taken by Bear Valley crews and First responders.
- Allows Bear Valley to remotely and rapidly de-energize sections of circuits when the circuit is determined to be at high risk of causing an ignition, which may result in a wildfire, thereby removing risk while minimizing impact to unaffected portions of the circuit and customers served.
- If Bear Valley were to lose some or all of its power supplies from SCE due to SCE directed Public Safety Power Shutoff, wildfires or other disasters affecting SCE power lines, or for other reasons, Bear Valley would have to implement a rolling blackout strategy since the Bear Valley Power Plant is not capable of supporting all loads. Currently, executing switching operations associated with a rolling blackout is very labor intensive and cumbersome due to manual switching.
- This project would allow for quick and efficient remote switching operations at the circuit level minimizing the impact to customers. It should be noted that during the Holcomb Fire in June 2017 Bear Valley had to implement a rolling blackout

strategy for several days when SCE's supply power lines to Bear Valley were damaged and de-energized due to the wildfire.
- Enable plan to support and actions taken to mitigate or reduce Public Safety Power Shutoff (PSPS) events in terms of geographic scope and number of customers affected, such as installation and operation of electrical equipment to sectionalize or island portions of the grid or local generation.
- When an outage occurs, Bear Valley will be able to rapidly assess the extent of the outage based on field switch positions indicated in SCADA.
- When an outage occurs, Bear Valley will be able to rapidly assess the boundaries of potential faults that caused the outage, which will allow responding crews to be rolled to the near exact fault location rather than waste significant time patrolling and hunting for the fault. Rapid fault localization may reduce the risk of ignitions resulting in wildfires and clearly has an impact on reducing time to restore service from outages.
- Significantly reduce outage time for customers by enabling quick restoration of unaffected portions of the distribution system when the fault is localized. The project prioritizes certain "tie" switches between circuits, which are normally "open." This would allow powering the unaffected portions of circuits remotely with alternate power sources thereby improving system reliability and resilience.
- Automated switches would also be capable of tying into Bear Valley's Fault, Localization, Isolation, and System Restoration (FLISR) System providing greater automatic restoration capability to customers following a faulted event.
- Vastly enhance grid resilience by enabling informed and rapid switching at the distribution and sub-transmission level during faulted, storm, and/or other disaster conditions.

Impact of the activity on wildfire risk

Impacts on wildfire risk are listed above in the initiative overview. Switches were involved in approximately 1 percent (51 instances) of all utility caused ignitions in the HFTD as recorded in the CPUC ignition database (2014 to 2023 data). The wildfire risk reduction is expected to be 4.41 percent each year of this WMP (2026 to 2028) as determined by the SMJU 7x7 Risk Based Decision Making Model.

Impact of the activity on outage program risk

Impacts on outage program risk and PSPS risk are listed above in the initiative overview. This initiative will reduce outage duration by allowing for rapid localization of a fault, isolation of the fault, and restoration of unaffected circuits. Furthermore, PSPS scope will be reduced by allowing for sectionalizing of circuits such that only the areas that exceed PSPS thresholds are de-energized.

Updates to the activity

Bear Valley began this initiative in 2023 as part of its 2023-2025 WMP. As of December 31, 2024, Bear Valley had automated 23 switches. In 2025, Bear Valley plans to automate another 11 switches. During this WMP Bear Valley will automate 10 switches each year (2026 to 2028).

Compatible activities

This initiative is compatible with the Equipment Settings to Reduce Wildfire Risk (GD_18). Having the capability to remotely enable Enhanced Power Line Safety Settings (EPSS) is a key component to rapidly established or de-establishing EPSS on applicable devices as the Fire Potential Index changes.

8.2.8.2 Capacitor Bank Upgrade Project (GD_9)

Overview of the activity:

The Capacitor Bank Replacement Project aims to replace 24 aging capacitor banks. Bear Valley's 2023-2025 WMP aimed to replace 18 capacitor banks with updated SCADA enabled capacitor banks. The remaining 6 capacitor banks will be replaced in 2026 during the period of this WMP. The existing capacitor banks are manually operated units, are nearing the end of their useful life (all greater than 40 years old), and are showing the telltale signs of eventual failure in electronic performance. The capacitors will be replaced with 450KVAR 3Phase units that are fully capable of being connected to SCADA for remote control and monitoring. Connectivity to SCADA will be via radio/cellular data transfer equipment and the BVES service area fiber optic network. This will allow Bear Valley to control voltage by placing or removing the capacitor banks from service as needed without having to send a crew to manually operate the capacitor banks. Additionally, the capacitor banks will be continuously monitored to ensure the banks do not overheat or have excessive voltage which may lead to catastrophic failure.

Impact of the activity on wildfire risk:

Capacitors were involved in approximately 1.5 percent (84 instances) of all utility caused ignitions in the HFTD as recorded in the CPUC ignition database (2014 to 2023 data). The wildfire risk reduction is expected to be 5.16 percent in 2026 as determined by the SMJU 7x7 Risk Based Decision Making Model.

Impact of the activity on outage program risk:

This initiative is not expected to have an impact on outage program risk or PSPS reduction. In the last 10 years, Bear Valley experienced one outage related to a capacitor failing to operate correctly.

Updates to the activity

Bear Valley's 2023-2025 WMP aimed to replace 18 capacitor banks with updated SCADA enabled capacitor banks. As of January 31, 2025, Bear Valley had replaced 12 capacitor banks and connected them to SCADA. Another 6 capacitor banks will be replaced and connected to SCADA in 2025. The remaining 6 capacitor banks will be replaced and connected to SCADA in 2026.

Compatible activities

There are no other activities Bear Valley uses in combination with this initiative.

8.2.8.3 Fuse TripSaver Automation Project (GD_10)

Overview of the activity:

This project aims to connect and automate 30 Fuse TripSavers to Bear Valley's SCADA network over the 3 years of this WMP (10 per year). A Fuse TripSaver is a device used by BVES in lieu of fuse cutouts on laterals, feeders, or circuit sections. The TripSaver improves system reliability by eliminating the permanent outages caused when lateral fuses respond to temporary faults. When the device is in "automatic" mode, the device keeps the power on and avoids truck rolls since power is restored automatically for transient faults similar to the way a re-closer would restore power. During high fire threat weather, the TripSavers are placed in "manual"; such that when a fault is detected, the device drops out and requires crew response similar to conventional fuses. Unlike a conventional fuse, there is no expulsion of metal slag that could cause an ignition. The advantage of the TripSaver is that in addition to having an "automatic re-close" or "manual" one shot mode of operation, it is programmable with various selectable protection curves (time vs. current curves) and it will behave like a conventional fuse. The settings may be optimized for reliability during a storm or ignition prevention during high fire threat weather. By connecting the TripSavers to the SCADA network, they can be monitored and operators would be alerted when a TripSaver actuates on fault. This provides prompt notification of a potential fault and ignition as well as localizing information; thereby, vastly improving response times. Additionally, by connecting the TripSavers to the SCADA network, they can be remotely programmed allowing the utility to rapidly optimize the TripSavers for fire prevention during high fire threat weather. Currently, Bear Valley crews must drive to each TripSaver and change their program operation, which takes several days. Therefore, Bear Valley operates the TripSavers in "manual" one-shot mode from April to November/December depending on the weather outlook. This project will establish a robust and secure IP communications network across the sub-transmission and distribution systems to fully enable monitoring of the TripSavers. Connectivity to SCADA will be via the BVES service area fiber optic network and via radio/cellular data transfer equipment.

Impact of the activity on wildfire risk:

By automating the Fuse TripSavers BVES will be able to switch the devices rapidly and remotely to "manual" to prevent them from reclosing following a fault detection (over current) where and when the FPI is "High" or higher. This flexibility is critical to striking a balance between wildfire risk mitigation when the FPI warrants it and making the system more reliable when FPI is lower. Being able to remotely detect when a Fuse TripSaver trips will have positive impact on reliability because crews will be immediately alerted and can take action to investigate the fault. This will allow crews to rapidly respond to faults that could develop into potential ignition sources. The wildfire risk reduction is expected to be 3.68 percent each year of this WMP (2026 to 2028) as determined by the SMJU 7x7 Risk Based Decision Making Model.

Impact of the activity on outage program risk

From 2022 to 2024, Bear Valley recorded 19 instances of Fuse TripSavers tripping. Being able to remotely detect when a Fuse TripSaver trips will have a positive impact on reliability because crews will be immediately alerted and can take action to investigate the fault; thereby, reducing the outage duration. It is estimated on average, each outage duration could be reduced by over 50 percent; thereby, improving reliability. PSPS thresholds assume Fuse TripSavers are in Manual (one shot). Being able to remotely determine each Fuse TripSavers mode of operation and shift modes will allow PSPS thresholds to not be adjusted lower.

Updates to the activity

In its 2023-2025 WMP, Bear Valley planned to automate 110 Fuse TripSavers. As of February 12, 2025, Bear Valley automated 60 Fuse TripSavers. In 2025, Bear Valley plans to automate the additional 50 Fuse TripSavers. During this WMP Bear Valley will automate 10 Fuse TripSavers each year (2026 to 2028).

Compatible activities

This initiative is compatible with the Switch and Field Device Automation (GD_8) initiative. Because switches and Fuse TripSavers must have connectivity with the BVES SCADA network, devices in the vicinity of each other are grouped together from a connectivity standpoint.

8.2.9 Line Removal (in the HFTD) (Tracking ID: None assigned)

Bear Valley does not have any line removal projects planned during the period of 2026 to 2028. Bear Valley's Covered Conductor Replacement Project (GD_1) does not involve abandoning lines but rather reconductoring lines. Bear Valley does not have any projects that convert overhead facilities to underground facilities; therefore, there are no line removals planned.

8.2.10 Other Grid Topology Improvements to Minimize Risk of Ignitions (Tracking ID: GD_11 and GD_12)

BVES has two initiatives in this activity. They are:

- (Tracking ID: GD_11) Utility Initiative Name: Non-Exempt Surge Arrester Replacement
- (Tracking ID: GD_12) Utility Initiative Name: Tree Attachment Removal Project

8.2.10.1 Non-Exempt Surge Arrester Replacement Project (GD_11)

Overview of the activity:

Lightning arresters are pieces of electrical equipment designed to mitigate the impact of transient overvoltage on the electric system. If the overvoltage duration is too long or too high, the arrester can become thermally overloaded, causing these units to fail in a way where they can become an ignition source.

This initiative is designed to replace the remaining lightning/surge arresters that are not exempted by CAL FIRE with CAL FIRE-approved arresters. CAL FIRE-approved lightning arresters are equipped with an external device that operates prior to the arrester overloading, dramatically reducing the potential of becoming an ignition source. Bear Valley has been removing the non-exempt arresters during the period of its 2023-2025 WMP and anticipates that there will be 58 non-exempt arresters remaining in the system at the start of 2026. Therefore, this initiative will target to remove these 58 non-exempt arresters by the end of 2026.

Impact of the activity on wildfire risk

Arresters were involved in approximately 1 percent (48 instances) of all utility-caused ignitions in the HFTD as recorded in the CPUC ignition database (2014 to 2023 data). The wildfire risk reduction is expected to be 3.46 percent in 2026 as determined by the SMJU 7x7 Risk Based Decision Making Model.

Impact of the activity on outage program risk:

This initiative is not expected to have an impact on outage program risk or PSPS reduction. In the last 10 years, Bear Valley did not experience any outages related to non-exempt arresters.

Updates to the activity

Bear Valley began removing the non-exempt arresters during the period of its 2023-2025 WMP and anticipates that there will be 58 non-exempt arresters remaining in the system at the start of 2026.

Compatible activities

Bear Valley combines non-exempt arrester replacement with the Covered Conductor Replacement Project (Reconductor)(GD_1) work for poles that are identified as having the non-exempt arresters. The remaining arresters are removed as a targeted effort.

8.2.10.2 Tree Attachment Removal Project (GD_12)

Overview of the activity

This Tree Attachment Removal Project initiative captures the work to remove legacy service attachments and wires that are affixed to trees, replacing with structures and poles that are more fire resistant. Tree attachments are pieces of electrical infrastructure fastened to trees instead of poles for infrastructure support. This condition inherently introduces ignition risk by holding energized wires in direct proximity to vegetation.

Bear Valley began removing tree attachments in a dedicated effort in 2018. At the start of this effort there were approximately 1,207 tree attachments in its service area, mostly located in U.S. Forest Service controlled areas. These tree attachments were installed many years ago. This is an ongoing project that began in previous WMPs where BVES removed approximately 100 tree attachments per year. At the start of 2026, it is estimated that there will be 245 of the original 1,207 tree attachments. Bear Valley intends to remove 100 tree attachments in 2026, 100 in 2027 and 45 in 2028.

Impact of the activity on wildfire risk

For some time now, the practice of installing distribution and service lines using tree attachments has been prohibited for new installations. Given that BVES's service area is entirely located in HFTD Tiers 2 and 3, tree attachments have been recognized as a high-risk condition. Elimination of tree attachments will enhance the safety and reliability of the distribution system and reduce the risk of wildfires. The wildfire risk reduction is expected to be 5.56 percent in 2026, 5.56 percent in 2027 and 2.5 in 2028 as determined by the SMJU 7x7 Risk Based Decision Making Model.

Impact of the activity on outage program risk

This initiative is not expected to have any measurable impact on outage program risk. Over the last 10 years, Bear Valley has not experienced an outage associated with a tree attachment. However, the fact that a circuit has a large number of tree attachments installed in it, factors into Bear Valley's evaluation for designating a circuit as a potential candidate for PSPS during extreme fire weather events.

Updates to the activity

BVES had approximately 1,207 legacy tree attachment service connections in its service area (2018 inventory count), mostly located in U.S. Forest Service controlled areas. As of December 31, 2024, BVES has removed 862 tree attachments. BVES will remove an additional 100 tree attachments in 2025 leaving 245 tree attachments to be removed during its 2026-2028 WMP. BVES is executing this initiative across the entire distribution system prioritized based on risk and accessibility(permitting). BVES plans to remove approximately 100 tree attachments per year in 2026 and 2027 and remove the remaining 45 in 2028.

Compatible activities

There are no other activities Bear Valley uses in combination with this initiative.

8.2.11 Other Grid Topology Improvements to Mitigate or Reduce PSPS Events (Tracking ID: None assigned)

Bear Valley currently does have any specific activities in this area. The objectives of this activity are achieved through Bear Valley's Automation Grid Hardening Initiatives that mitigate or reduce PSPS events, which are:

- Switch and Field Device Automation (GD_8)
- Fuse TripSaver Automation (GD_10)

8.2.12 Other Technologies and Systems Not Listed Above (Tracking ID: GD_13 and GD_14)

BVES has two initiatives in this activity. They are:

- (Tracking ID: GD_13) Utility Initiative Name: Safety and Technical Upgrades to Lake Substation Project
- (Tracking ID: GD_14) Utility Initiative Name: Partial Safety and Technical Upgrades to Village Substation Project

8.2.12.1 Safety and Technical Upgrades to Lake Substation Project (GD_13)

Overview of the activity

The existing Lake Substation is to be converted from an overhead-type to an underground pad-mounted design. This single 2.0 MVA transformer substation converts 34.5 kV sub-16 transmission to one 4.160 kV distribution circuit (Pump House circuit). The project will improve the safety, reliability and efficiency of the substation by eliminating a wiring configuration that is a potential safety issue, and replacing all aged substation equipment with more efficient and enclosed pad mount transformers, voltage regulators, circuit re-closers, and bus work. The transformation capability would be increased to 5 MVA to accommodate load growth and allow the Pump House circuit to pick up other circuits' loads for maintenance considerations and during faulted conditions to improve system reliability and resiliency. The equipment will be SCADA enabled with remote monitoring and operation capability. Advanced metering will be installed to provide real-time, high-quality circuit load data as well as reliability data. The transformer in the Lake Substation is approaching its maximum useful life. In the event of a major transformer failure at the Lake Substation, Bear Valley would not be able to restore the substation until a new or refurbished transformer is procured and delivered, which at a minimum would take a week but more likely several weeks due to supplier inventories and locations and the logistics of trucking such a transformer up the mountain roads to Big Bear Lake. The substation equipment is over 35 years old, which makes the equipment more prone to failure. This project will be started in 2026 and is expected to be fully completed by the end of 2027.

Impact of the activity on wildfire risk

The existing Lake Substation is an overhead, open bus type design. Because of this design, vegetation (leaves, branches, trees, etc.) could contact the energized bus and could cause an ignition potentially leading to potential ignition and wildfire. The new substation design uses a pad-mount dead-front design with no exposed energized conductors or equipment. The new "no-possible-contact" design reduces the ignition risk due to contact to near zero, essentially the maximum reduction possible when compared to an open bus design combined with vegetation management. The wildfire risk reduction is expected to be 4.65 percent in 2027 as determined by the SMJU 7x7 Risk Based Decision Making Model.

Impact of the activity on outage program risk

This project does not substantially impact outage program risk.

Updates to the activity

Bear Valley plans to start this project in 2026 and complete the work for this initiative by the end of 2027.

Compatible activities

There are no other activities Bear Valley uses in combination with this initiative.

8.2.12.2 Partial Safety and Technical Upgrades to Village Substation Project (GD_14)

Overview of the activity

This project replaces overhead enclosed regulators with pad mounted regulators, installs pad mounted IntelliRupter switches, and updates substation controls. This two 3.75 MVA transformer substation converts 34.5 kV sub-transmission to three 4.160 kV distribution circuits (Boulder, Harnish, and Lagonita circuits). These circuits provide power to critical infrastructure and small businesses and residential customers in the area. The reliability and safety of this substation is crucial to providing reliable and safe service to a substantial portion of BVES's customers. Two of the distribution circuits traverse high wind and high vegetation areas. The IntelliRupter switches will significantly improve the ability of the circuits to be rapidly de-energized when fault conditions are detected. The IntelliRupter when in automatic mode will test at approximately 10% power when a fault is detected, thereby significantly reducing the possibility of causing an ignition. The equipment will be SCADA enabled with remote monitoring and operation capability. The regulators and switches at Village Substation are over 30 years old and approaching their maximum useful life, which makes the equipment more prone to failure. Village Substation was partially upgraded in 1995 resulting in the feeds on both the sub-transmission and distribution sides being undergrounded and the transformers being pad mounted. The re-closers and regulators are of the overhead design. This project would complete the conversion of the substation to be completely underground with pad mounted equipment. At the completion of the project there would be no exposed bare wire or bus work. The project is scheduled to be conducted in 2028.

Impact of the activity on wildfire risk

The existing Village Substation is partly overhead, open bus type design. Because of this design, vegetation (leaves, branches, trees, etc.) could contact the energized bus and could cause an ignition leading to potential ignition and wildfire. The new substation design uses a pad-mount dead-front design with no exposed energized conductors or equipment. The new "no-possible-contact" design reduces the ignition risk to near zero, essentially the maximum reduction possible when compared to an open bus design combined with vegetation management. The wildfire risk reduction is expected to be

4.65 percent in 2028 as determined by the SMJU 7x7 Risk Based Decision Making Model.

Impact of the activity on outage program risk

This project does not substantially impact outage program risk.

Updates to the activity

Bear Valley plans to complete the work for this initiative by the end of 2028.

Compatible activities

There are no other activities Bear Valley uses in combination with this initiative.

8.2.13 Status Updates on Additional Technologies Being Piloted (Tracking ID: None assigned)

Bear Valley is not piloting any Grid Hardening technologies; therefore, currently does have any status updates on activities in this area.

8.3 Asset Inspections

Table 8-2. Asset Inspection Frequency, Method, and Criteria provides a summary of details regarding the asset inspections Bear Valley conducts.

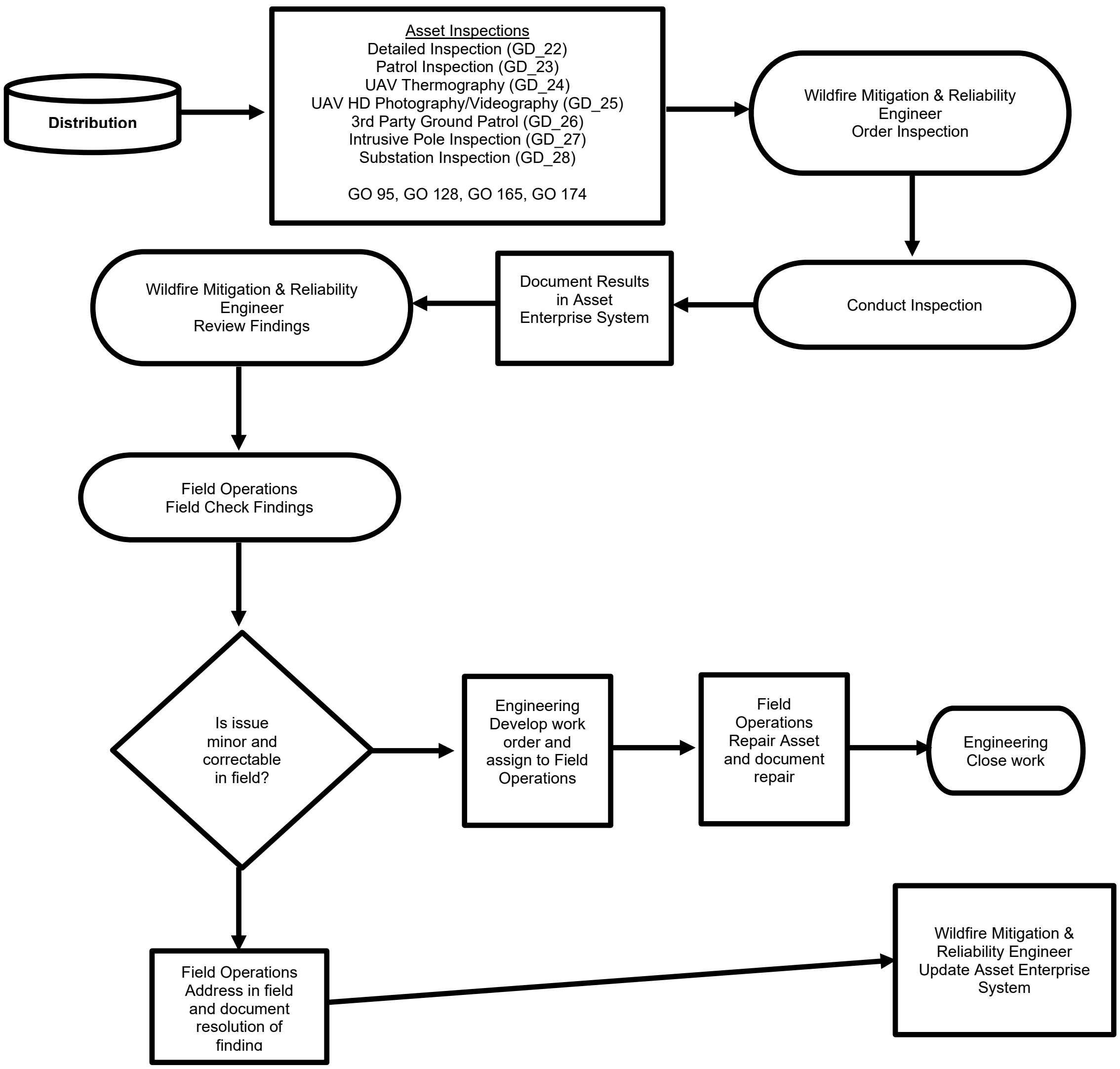
Table 8-2 Asset Inspection Frequency, Method, and Criteria

Type	Inspection Activity (Program)	Frequency or Trigger (Note 1)	Method of Inspection (Note 2)	Governing Standards & Operating Procedures	Cumulative Quarterly Target Year 1, Q1	Cumulative Quarterly Target Year 1, Q2	Cumulative Quarterly Target Year 1, Q3	Cumulative Quarterly Target Year 1, Q4	Cumulative Quarterly Target Year 2, Q1	Cumulative Quarterly Target Year 2, Q2	Cumulative Quarterly Target Year 2, Q3	Cumulative Quarterly Target Year 2, Q4	Cumulative Quarterly Target Year 3, Q1	Cumulative Quarterly Target Year 3, Q2	Cumulative Quarterly Target Year 3, Q3	Cumulative Quarterly Target Year 3, Q4	% of HFRA and HFTD Covered Annually by Inspection Type	Condition Find Rate Level 1	Condition Find Rate Level 2	Condition Find Rate Level 3
Transmission	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Distribution	Detailed	5 years Cycle	Ground Inspections	GO 165 & GO 95 (Rule18)	10	25	40	55	10	25	40	55	10	25	40	55	20	1% (Asset)	5 % (Asset)	15 % (Asset)
Distribution	Patrol	Annual	Ground Inspections	GO 165 & GO 95 (Rule18)	52	102	153	205	52	102	153	205	52	102	153	205	100	1% (Asset)	5 % (Asset)	10 % (Asset)
Distribution	UAV Thermography Inspection	Annual	Drone Inspection	GO 165 & GO 95 (Rule18)	0	0	205	205	0	0	205	205	0	0	205	205	100	1% (Asset)	5 % (Asset)	15 % (Asset)
Distribution	UAV HD Photography/Videography	Annual	Drone Inspection	GO 165 & GO 95 (Rule18)	0	0	205	205	0	0	205	205	0	0	205	205	100	1% (Asset)	10 % (Asset)	15 % (Asset)
Distribution	Third-Party Ground Patrol	Annual	Ground Inspections	GO 165 & GO 95 (Rule18)	0	0	205	205	0	0	205	205	0	0	205	205	100	1% (Asset)	10 % (Asset)	20 % (Asset)
Distribution	Intrusive Inspection	Per GO 165	Ground Inspections	GO 165 & GO 95 (Rule18)	0	0	850	850	0	0	850	850	0	0	850	850	10	1% (Asset)	15 % (Asset)	10 % (Asset)
Substation	Substation Inspection	Monthly	Ground Inspections	GO 174	36	72	108	144	36	72	108	144	36	72	108	144	100	1% (Asset)	5 % (Asset)	15 % (Asset)

Bear Valley's asset inspections follow similar workflows as depicted below in **Figure 8-1 Asset Management and Inspections Workflow**. This applies to the following asset inspections:

- Detailed Inspection (GD_22)
- Patrol Inspection (GD_23)
- UAV Thermography (GD_24)
- UAV HD Photography/Videography (GD_25)
- 3rd Party Ground Patrol (GD_26)
- Intrusive Pole Inspection (GD_27)
- Substation Inspection (GD_28)

Figure 8-1 Asset Management and Inspections Workflow



8.3.1 Detailed inspections (Tracking ID: GD_22)

8.3.1.1 Overview

A “detailed inspection” is a more careful visual and diagnostic examination of individual pieces of equipment. BVES’s Field Inspector performs the Detailed Inspections. The Field Inspector is required to be a Journeyman Lineman experienced in inspection of electric transmission and distribution facilities and power lines. The inspector records the results of the diagnostic and visual examinations and rates the condition of the equipment. These inspections are designed to identify any existing, including minor, defects. These may include, but are not limited to, open wire secondary clearance, corona effect on cross-arms, warning signage issues, visibility strips and pole-tag issues, and rotten poles. If any defects are identified, BVES prioritizes the defect resolution based on the hazard it poses and resolves the issues in compliance with GO 95 Rule 18 timeframes.

All inspection findings (detailed, patrol, UAV, etc.) are rated in accordance with GO 95 Rule 18 (level 1, 2, or 3) and entered into the distribution inspection GIS database. Level 1 findings are reported immediately to the Field Operations Supervisor who will direct corrective action as soon as possible to resolve the issue or reduce its severity to Level 2 so that more time is available to perform permanent corrective action.

The Wildfire Mitigation and Reliability Engineer reviews the results of all inspections and assigns corrective action to Field Operations. Additionally, the Wildfire Mitigation and Reliability Engineer reviews the results of Detailed Inspections as well as other asset inspections to determine if there are systemic issues that must be addressed. Finally, the results of Detailed Inspections are validated against other asset inspections to evaluate the quality and effectiveness of each inspection type.

8.3.1.2 Frequency or Trigger

Bear Valley conducts detailed inspections using a mix of schedule and risk prioritization in determining which circuits are to be inspected. GO 165 provides specific minimum inspection schedule criteria, which Bear Valley follows. For overhead systems, Bear Valley is required to inspect these systems every five years. Bear Valley inspects unhardened (bare conductor systems) at least every three years on a risk prioritization basis and hardened covered conductor systems every five years. All of Bear Valley’s unhardened bare conductor circuits are located in the HFTD Tier 2. All detailed inspections are conducted in compliance with GO 165 and GO 95 (Rule 18). BVES divides its system up and conducts detailed inspections on every circuit.

It should be noted that 100% of Bear Valley’s system is inspected via the following annual inspections:

- Patrol Inspections (GD_23)
- UAV Thermography Inspections (GD_24)
- UAV HD Photography/Videography Inspections (GD_25)

- 3rd Party Ground Patrol Inspections (GD_26)

8.3.1.3 Accomplishments, Roadblocks, and Updates

Bear Valley measures success by completing its annual target as scheduled to the required inspection standards. BVES completed 51 miles of detailed inspection to achieve its target of 51 miles in 2024. Bear Valley has not encountered any roadblocks to conducting detailed inspections. Starting in 2025 Bear Valley has created plans to increase the detailed inspections on circuits that have not been hardened (bare conductors) in areas of higher ignition risk using a risk-based prioritization FireSight model.

Bear Valley does not anticipate any changes/updates to this activity nor does BVES have any pilot projects or research in this area.

8.3.2 Patrol Inspection (Tracking ID: GD_23)

8.3.2.1 Overview

In compliance with GO 165 and GO 95, Bear Valley's Inspection Program requires a patrol inspection of all overhead facilities each year. A "patrol inspection" is a visual inspection designed to identify obvious problems, gross defects, and hazards. Gross defects may include, but are not limited to, cracked cross-arms, poles leaning beyond specification, guy wires missing or damaged, vegetation encroachment inside of minimum clearance standards, etc. These encroachments have the potential to spark and possibly ignite a wildfire. Patrol inspections are a critical element in mitigating the risk of wildfire caused by electric utility facilities. Bear Valley's Field Inspector performs the patrol inspections. The Field Inspector is required to be a Journeyman Lineman experienced in inspection of electric sub-transmission and distribution facilities and power lines.

8.3.2.2 Frequency or Trigger

Patrol inspections are conducted annually in compliance with GO 165. The inspections cover the entirety of Bear Valley's overhead facilities. Because all of Bear Valley's service area is in HFTD Tier 2 or Tier 3 and the entire system is inspected each year, risk prioritization is limited to the sequencing of inspecting circuits. Higher ignition risk circuits (unhardened bare conductor) are inspected prior to the fire season.

8.3.2.3 Accomplishments, Roadblocks, and Updates

Bear Valley measures success by completing its annual target as scheduled to the required inspection standards. BVES completed a patrol inspection of its entire system in 2024, which is its target. Bear Valley has not encountered any roadblocks to conducting patrol inspections. Starting in 2025, Bear Valley has plans to patrol inspect higher ignition risk circuits (unhardened bare conductor) prior to the fire season.

Bear Valley does not have any pilot projects or research in this area.

8.3.3 UAV Thermography (Tracking ID: GD_24)

8.3.3.1 Overview

The UAV thermographic survey provides quick and meaningful inspection results other inspection methods are not able to provide. The ability to identify “hot spots” is unique to this inspection technology. Generally, thermographic hot spots are indicative of potential equipment degradation or failure.

When BVES receives the thermography survey report, each finding is investigated by qualified personnel in evaluating asset conditions to validate the identified conditions and reassign the priority per GO 95, if deemed appropriate. The thermography contractor will immediately inform BVES of any level 1 findings so that they may be corrected or resolved to a level 2 or 3 finding as soon as possible.

The Wildfire Mitigation and Reliability Engineer reviews the results of thermography surveys and assigns corrective action to the line crews. Additionally, the Wildfire Mitigation and Reliability Engineer reviews the result of thermography surveys as well as other vegetation inspections to determine if there are systemic issues that must be addressed. Finally, the results of thermography surveys are cross checked against other asset inspections to evaluate the quality and effectiveness of each inspection type.

8.3.3.2 Frequency or Trigger

UAV thermography inspections are conducted annually and cover the entirety of Bear Valley’s overhead facilities. Bear Valley’s entire service territory is in HFTD Tier 2 or Tier 3 and is very compact and the UAV thermography inspection data collection is done over a short period of time, therefore risk prioritization scheduling is not used in assigning these inspections.

8.3.3.3 Accomplishments, Roadblocks, and Updates

Bear Valley measures success by completing its annual target as scheduled to the required inspection standards. Bear Valley completed 205 miles of UAV thermography inspection to complete the target of 205 miles in 2024. Bear Valley started conducting UAV thermography inspections in 2021 and has completed 4 annual inspections. Bear Valley has not encountered any roadblocks to conducting UAV thermography inspections. Currently, Bear Valley is not considering any new strategies for the UAV thermography inspection.

Bear Valley does not have any pilot projects or research in this area.

8.3.4 UAV Photography/Videography (Tracking ID: GD_25)

8.3.4.1 Overview

BVES will contract UAV fly-over inspections of its sub-transmission and distribution system. This inspection complements the Ground Patrols and detailed inspections of GO

165. Many electric utilities, including major California electric utilities, have found inspections utilizing UAVs are highly effective at identifying facilities degradations and issues that Ground Patrols and detailed inspections would not necessarily reveal. The UAVs film the facilities using high-definition video photography while maintaining an accurate date/time and geolocation stamp on the recorded video stream. The video recordings are then reviewed by qualified analysts who can slow down the recording so as to note any issues. When a potential issue is identified, they can freeze the video and perform further analysis such as zooming in on the item in question. Discrepancies are then identified, evaluated, recorded, and remediation or further investigation is assigned.

The UAVs used for this inspection will also collect infrared thermography data for analysis. This technology includes heat-sensing cameras that can identify risk drivers such as increased “hot” areas or conditions that may indicate deterioration, which can lead to potential failures and ignitions.

The Wildfire Mitigation and Reliability Engineer reviews the results of the UAV Imagery surveys and assigns corrective action to the line crews. Findings are handled in the same manner as described above. Additionally, the Wildfire Mitigation and Reliability Engineer reviews the results of the UAV Imagery surveys as well as other asset inspections to determine if there are systemic issues that must be addressed. Finally, the results of the UAV Imagery surveys are cross checked against other asset inspections to evaluate the quality and effectiveness of each inspection type.

8.3.4.2 Frequency or Trigger

UAV HD Photography/videography inspections are conducted annually and cover the entirety of Bear Valley’s overhead facilities. All of Bear Valley’s service territory is in HFTD Tier 2 or Tier 3 and is very compact and the UAV HD Photography/videography inspection data collection is done over a short period of time, therefore risk prioritization scheduling is not used in assigning these inspections.

8.3.4.3 Accomplishments, Roadblocks, and Updates

Bear Valley measures success by completing its annual target as scheduled to the required inspection standards. Bear Valley completed 205 miles of UAV photography/videography inspection to complete the target of 205 miles in 2024. Bear Valley started conducting UAV photography/videography inspections in 2021 and has completed 4 annual inspections. Bear Valley has not encountered any roadblocks to conducting patrol inspections. Currently, BVES is not considering any new strategies for the UAV photography/videography inspection.

Bear Valley does not have any pilot projects or research in this area.

8.3.5 3rd Party Ground Patrol (Tracking ID: GD_26)

8.3.5.1 Overview

This inspection conducted by a contracted 3rd party satisfies GO 165 patrol inspection requirements and is in effect an additional annual GO 165 patrol inspection to the one that the Bear Valley's Field Inspector performs. Bear Valley contracts experienced and qualified electrical distribution asset inspection contractors to perform this ground patrol inspection.

Bear Valley assesses that this additional patrol is warranted due to the local climate; likelihood of icing conditions; tree limbs and branches subject to weakening due to repeated high winds, snow, and ice weight (which may cause fatigue failure); high elevation; other local conditions; difficultly accessing vegetation for trimming near bare conductors; species growth rates and characteristics; and the fact that the service area is designated "very dry" or "dry" approximately 80 percent of the time in the NFDRS. This environment, coupled with the fact that the fire season is now year-round, creates a high-risk condition that can be mitigated by increasing patrols. Substandard conditions detected on the second ground patrol are addressed in the same manner as the first patrol in compliance with GO 95 and 165.

3rd Party Ground Patrol Inspection findings are rated and handled in the same manner as BVES's inspection findings in accordance with GO 95 Rule 18 (level 1, 2, or 3) and entered into the distribution inspection GIS data base. Level 1 findings are reported immediately to the Field Operations Supervisor who will direct corrective action as soon as possible to resolve the issue or reduce its severity to Level 2 so that more time is available to perform permanent corrective action.

8.3.5.2 Frequency or Trigger

The 3rd Party Ground Patrol inspections are conducted annually and cover the entirety of Bear Valley's overhead facilities. Because all of BVES's service territory is in HFTD Tier 2 or Tier 3 and this 3rd party ground patrol is performed in a short period (about 4 weeks) on the entire system, risk prioritization scheduling is not used in assigning these inspections.

8.3.5.3 Accomplishments, Roadblocks, and Updates

Bear Valley measures success by completing its annual target as scheduled to the required inspection standards. BVES completed 205 miles of the 3rd party ground patrol inspection to complete the target of 205 miles in 2024. Bear Valley started conducting 3rd party ground patrol inspections in 2019 and has completed 6 annual inspections. Bear Valley has not encountered any roadblocks to conducting patrol inspections. Currently, BVES is not considering any new strategies for the 3rd party ground patrol inspection.

Bear Valley does not have any pilot projects or research in this area.

8.3.6 Intrusive Pole Inspection (Tracking ID: GD_27)

8.3.6.1 Overview

In accordance with GO 165, this initiative monitors the age and structural integrity of existing wood poles through means of a more detailed assessment of the pole's condition such as coring areas of identified damage and visual inspection of the poles apart from pole loading assessments results. Intrusive inspections involve movement of soil, taking samples for analysis, and using more sophisticated diagnostic tools beyond visual inspections of instrument reading. Bear Valley's intrusive pole inspection contractor utilizes the IML-RESI PowerDrill® to perform a non-destructive pole intrusive inspection. The IML-RESI assesses wood quality by measuring the drill's needle resistance through the core of the wood being inspected. The results are captured by proprietary Alatrac data collection software automatically and translates the IML-RESI's boring results into Industry standard pole strength analysis that is based on the RUS 1730B-121 Wood Pole and Maintenance Bulletin. The inspection graphing result is tied to an online inspection record, along with photos and GPS.

8.3.6.2 Frequency or Trigger

BVES conducts Intrusive Pole Inspection on a cycle that maintains compliance with GO 165 based on the type of pole as well as if/when an intrusive inspection was previously conducted. Wood poles over 15 years which have not been subject to intrusive inspection are due for inspection in 10 years. Wood poles which previously passed intrusive inspection are due every 20 years. When the inspection determines the pole no longer has the required strength, the pole is scheduled for replacement. This program determines the health of existing poles. BVES routinely intrusively inspects poles as part of its Pole Loading and Assessment program and performs directed intrusive inspections as needed. Because all of BVES's service territory is in HFTD Tier 2 or Tier 3, risk prioritization scheduling by area is not used in assigning these inspections. BVES schedules these inspections based upon the age of the poles and the order of the review cycles, in addition to other efforts such as pole loading assessments or pole replacement projects which are prioritized by risk.

8.3.6.3 Accomplishments, Roadblocks, and Updates

Bear Valley measures success by completing its annual target as scheduled to the required inspection standards. BVES completed 850 intrusive inspections to complete the target of 850 poles in 2024. Bear Valley has not encountered any roadblocks to conducting patrol inspections. Currently, BVES is not considering any new strategies for the intrusive pole inspection.

Bear Valley does not have any pilot projects or research in this area.

8.3.7 Substation inspection (Tracking ID: GD_28)

8.3.7.1 Overview

Substation transformer and other equipment inspections are mandated by the CPUC through GO 174 facilities inspections. Substation inspections provide both reliability and incidental wildfire mitigation benefits. Substation inspections mitigate the risk of equipment failures which have the potential to cause wildfire ignitions. The inspections also provide benefits when a substation is in the HFTD or wildland-urban interface. Gas - in-oil analysis is performed every year. If gas is detected in the oil, a cause analysis is performed to determine if the transformer can be repaired or requires replacement. Other inspections such as oil levels, temperature, and contamination are also performed. These inspections will determine when a transformer is nearing its end of life so it can be scheduled for replacement.

Protective relays are used extensively across the power system to remove any element from service that suffers a short circuit, starts to operate abnormally, or poses a risk to the operation of the system. It is essential to inspect and test substation protective relays at chosen intervals. The frequency of maintenance inspections and tests depends on the quality of the equipment, importance of the supply, and upon the conditions at the site where the relays are installed. Protective substation relays are inspected, tested, and calibrated on a periodic basis to assure proper operation.

8.3.7.2 Frequency or Trigger

Substation Inspection – BVES conducts Substation Inspections for all 13 substations on a monthly basis in compliance with GO 174. Presently, the periodic inspection for relays is every four years. If proper operation cannot be assured, for instance due to obsolescence, the relay is scheduled for replacement.

8.3.7.3 Accomplishments, Roadblocks, and Updates

Bear Valley measures success by completing its annual target as scheduled to the required inspection standards. BVES completed 156 substation inspections to complete the target of 144 inspections in 2024. Bear Valley has not encountered any roadblocks to conducting patrol inspections. Currently, BVES is not considering any new strategies for the substation inspection program.

Bear Valley does not have any pilot projects or research in this area.

8.4 Equipment Maintenance and Repair

8.4.1 Capacitors (Tracking ID: GD_5 & GD_9)

In BVES's 2023-2025 WMP, BVES established a Capacitor replacement program to replace all 24 existing capacitor banks from 2023 – 2026. As of the beginning of 2025, BVES has already replaced 12 capacitor banks and is on-track to replace 6 more capacitor banks by end of 2025. BVES plans to continue replacing the last 6 capacitor banks by end of 2026.

As part of the replacement program new capacitor banks will be 3-phase automatic switching banks rated for 450kVARs units total with SCADA capability. Radio/Cellular communication interface are used to communicate to BVES SCADA system. BVES SCADA system allows BVES operators optimizing remote operation, control and monitoring of the capacitor bank system as needed, without sending a crew to manually operate the capacitor banks. In addition, the capacitor banks will continuously monitor the voltage, current, and VARS to assist improving power factor/voltage corrections downstream of the circuit. Data collection is available in which BVES will have a historical database of various information such as voltage, control status for review to make adjustment as needed.

The new capacitor banks will replace significantly aging (>40 years old) manually operated fixed capacitor banks. The existing capacitor banks are beginning to show signs of possible future failure, which in the worst case could result in explosion of the capacitor and the potential for ignition.

Capacitor banks are inspected with following inspection programs:

- Detailed asset inspections (GD_22)
- Patrol asset inspections (GD_23)
- UAV thermography asset inspections (GD_24)
- UAV photography/videography asset inspection (GD_25)
- 3rd party ground patrol asset inspections (GD_26)
- Anytime a capacitor bank is placed in service or removed from service basic inspection maintenance is performed in accordance with BVES's Capacitor Operation Maintenance Policy and Procedures.

All of these programs are part of ongoing electrical maintenance and prevention activities intended to provide a plan for any remediation, adjustments, or installations of new equipment to improve or replace existing capacitors which reduces the likelihood of faults or failures that may result in ignitions. BVES does not run its capacitors to failure.

In the last 3 years, 1 capacitor experienced a failure. All of Bear Valley's service area is in the HFTD. There are a total of 24 capacitors in the BVES. Failure rate is 4.17%. Note that from 2023 to 2026 all of Bear Valley's capacitors will be replaced so this failure rate is most likely not representative of the expected failure rate over the next 10-20 years.

Bear Valley has not experienced any ignitions from this equipment.

8.4.2 Circuit Breakers (Tracking ID: GD_5)

BVES routinely maintains and repairs its circuit breakers to prevent ignition risk and aid in future fault detection deployments. Specifically, this activity addresses the remediation, adjustments, or installations of new equipment to improve or replace existing fast switching circuit breaker equipment to improve the ability to protect electrical circuits from damage caused by overload of electricity or short circuit.

Circuit breakers are inspected as part of substation inspection per the CPUC GO 174 facilities inspections. Circuit breakers are used for high voltage switching and to isolate faults in a timely manner before the faults can cascade into a complete system outage. Circuit breakers in a substation protect the power grid from fault events such as a surge in voltage due to a lightning strike. Circuit breakers are generally inspected and maintained periodically every four years. BVES policy does not allow its circuit breakers to run to failure. Depending on the type of breaker, these inspection and maintenance tests include oil analysis, vacuum/gas checks, speed analysis, or other industry analysis standards.

In the last 3 years, no circuit breakers experienced failures. All of Bear Valley's service area is in the HFTD. Failure rate is 0.0%.

Bear Valley has not experienced any ignitions from this type of equipment.

8.4.3 Connectors, Including Hotline Clamps (Tracking ID: GD_15)

BVES routinely maintains these electrical assets to prevent ignition risk through operations and maintenance practices. This activity addresses the remediation, adjustments, or installation of new equipment to improve or replace existing connectors, including hotline clamps. This maintenance of equipment aims to improve the ability to protect electrical circuits from damage or ignition caused by overload of electricity or short circuit.

BVES does not have any hotline clamps on its sub-transmission system (34 kV) and does not have any hotline clamps in the HFTD Tier 3. Maintenance is achieved through the following inspections:

- Detailed asset inspections (GD_22)
- Patrol asset inspections (GD_23)
- LiDAR asset inspections (VM_4)
- UAV thermography asset inspections (GD_24)
- UAV photography/videography asset inspection (GD_25)
- 3rd Party Ground Patrol asset inspection (GD_26)

Hotline clamps are rarely found in the BVES system. Because distribution voltage is 4 kV; generally, hotline clamping is not necessary.

Currently, BVES's policy is that when a hotline clamp is found it is recorded in the GIS system and reported to the Field Operations Supervisor and Engineering staff. It is then scheduled for removal as soon as feasible and once removed from the system, GIS is updated to reflect its removal.

In the last 3 years, 4 connectors failed. All of Bear Valley's service area is in the HFTD. There are approximately 20,000 connectors in the BVES system. Failure rate is 0.02%.

Bear Valley has not experienced any ignitions from this equipment.

8.4.4 Conductor, Including Covered Conductor (Tracking ID: GD_1)

BVES will maintain its conductors, including covered conductors as described below and has established a separate initiative for maintenance activities. Conductors are inspected as follows:

- Detailed asset inspections (GD_22)
- Patrol asset inspections (GD_23)
- LiDAR asset inspections (VM_4)
- UAV thermography asset inspections (GD_24)
- UAV photography/videography asset inspection (GD_25)
- 3rd Party Ground Patrol asset inspection (GD_26)

Covered conductor issues identified in the inspections are documented and corrected in accordance with GO 95 Rule 18 prioritization.

With respect to covered conductors, Bear Valley was advised by the manufacturer that periodic visual inspections that are normally conducted on overhead systems (such as patrols and detailed inspections) should include looking for significant discoloration, bubbling and separation of the outer coating from the covered conductor cable, and signs of abrasions that penetrate through the outer coating. These instructions are provided to the Field Inspector.

BVES participates in the joint utilities workshop on covered wire and will continue to exchange information in this area with other utilities. BVES will attend T&D conferences and review T&D literature and periodicals on the latest in covered wire operations and maintenance.

BVES conducted discussions with cable manufacturers on the techniques to handle water intrusion and will develop a strategy for this issue. The manufacturers recommend that periodic visual inspections that are normally conducted on overhead systems (such as patrols and detailed inspections) should include looking for significant discoloration, bubbling, change in sag with-in the conductor span between phases and separation of the outer coating from the covered conductor cable, and signs of abrasions that penetrate through the outer coating. BVES will update its patrol and detailed inspection checklists to include these items.

Starting in 2025, BVES is using an upgraded covered conductor with a water blocker. Bear Valley keeps track of where covered conductors were installed that did not have the water blocker. The inspectors for the inspections discussed above are alerted to pay particular attention to these areas in their inspections. Signs of water intrusion are significant discoloration, bubbling, change in sag with-in the conductor span between phases and separation of the outer coating from the covered conductor cable, which are included in the inspection instructions discussed above.

In the last 3 years, 4 conductor failure incidents occurred. All of Bear Valley's service area is in the HFTD. There are approximately 70,000 spans in the BVES system. Failure rate is 0.00575%. There were no covered conductor failures.

Bear Valley has not experienced any ignitions from this equipment

8.4.5 Fuses, Including Expulsion Fuses (Tracking ID: GD_10)

As of December 31, 2021, BVES replaced all of its conventional fuses by installing current limiting fuses (ELF) and electronic programmable fuses (S&C TripSavers) system wide. The current limiting fuses and electronic fuses expel no materials, limit the available fault current, and may even reduce the duration of faults. Beginning in 2022, BVES shifted its fuse replacement program from a system hardening type initiative to a normal operations and maintenance initiative, with the focus of maintaining the updated fuses in the system. BVES will continue to replace blown or faulty fuses with the ELF type fuses or electric fuses as applicable. BVES will also perform maintenance on Fuse TripSavers to manufacturer's specifications.

Fuses are inspected as follows:

- Detailed asset inspections (GD_22)
- Patrol asset inspections (GD_23)
- UAV thermography asset inspections (GD_24)
- UAV photography/videography asset inspection (GD_25)
- 3rd Party Ground Patrol asset inspection (GD_26)

Fuse issues identified in the inspections are documented and corrected in accordance with GO 95 Rule 18 prioritization.

In the last 3 years, Bear Valley had 10 fuses events. All of Bear Valley's service area is in the HFTD. There are approximately 2,578 fuses in the BVES system. Failure rate is 0.39%. There were no Fuse TripSaver failures.

Bear Valley has not experienced any ignitions from this equipment.

8.4.6 Distribution Poles (Tracking ID: GD_3 & GD_4)

GO 95 Rule 43.1 requires BVES to design, build, and maintain their overhead facilities to withstand foreseeable fire and wind conditions in the service territory. All Bear Valley's poles are above 3,000 feet; therefore, "heavy loading" specifications and safety factors are used.

Poles are inspected as follows:

- Detailed asset inspections (GD_22)

- Patrol asset inspections (GD_23)
- UAV photography/videography asset inspection (GD_25)
- 3rd Party Ground Patrol asset inspection (GD_26)
- Intrusive Pole Inspections (GD_27)

Anytime an addition or attachment to a pole is planned, a full loading assessment is performed to ensure proper safety factor exists.

Poles that are not compliant with GO 95 safety factors will be identified, and the appropriate remediation will be designed and implemented. Meeting or exceeding the mandates of GO 95 is critical to mitigate wildfires. Depending on the nature and extent of the noncompliance, the remediation will require either repair (e.g., the installation or modification of guy wires) or complete replacement of the pole, including removal and reinstallation of all attachments, all within the time frames required by GO 95. GO 95 is aimed at the safety of personnel, the public, and preserving the reliability of the power grid. Risk is significantly reduced when poles are brought into compliance with laws directed at preserving safety and reliability. BVES uses preventative maintenance to identify poles at risk.

In the last 3 years, Bear Valley had 0 pole failures. All of Bear Valley's service area is in the HFTD. There are approximately 8,913 poles in the BVES system. Failure rate is 0.0%.

Bear Valley has not experienced any ignitions from this equipment.

8.4.7 Lightning arrestors (Tracking ID: GD_3, GD_4, GD_25 & VM_3)

BVES installs lightening arrestors that are approved for use in all areas of California in accordance with GO-95. Lightning arrestors are inspected as follows:

- Detailed asset inspections (GD_22)
- Patrol asset inspections (GD_23)
- UAV thermography asset inspections (GD_24)
- UAV photography/videography asset inspection (GD_25)
- 3rd Party Ground Patrol asset inspection (GD_26)

Defective arrestors are replaced. Additionally, during pole replacements arrestors are also replaced. As reported in Area for Continuous Improvement BVES 23-14, Bear Valley replaced 43 non-exempt lightning/surge arresters with exempt lightning/surge arresters 2023. In 2024, Bear Valley replaced 58 nonexempt lightning/surge arresters with the goal of replacing the remaining 115 nonexempt lightning/surge arresters by the end of 2026.

In the last 3 years, Bear Valley had 0 lightning arrester failures. All of Bear Valley's service area is in the HFTD. Failure rate is 0.0%.

Bear Valley has not experienced any ignitions from this equipment.

8.4.8 Reclosers (Tracking ID: GD_8)

BVES system has 1-2 Aerial Reclosers each on the 4kV distribution circuits located along the lines. In 2023, BVES started to automate switch and field devices. BVES plans to replace the remaining oil filled Aerial Reclosers with Vacuum Interrupter Pulse Closing switches by end of 2026.

Recloser are inspected as follows:

- Detailed asset inspections (GD_22)
- Patrol asset inspections (GD_23)
- UAV thermography asset inspections (GD_24)
- UAV photography/videography asset inspection (GD_25)
- 3rd Party Ground Patrol asset inspection (GD_26)

Reclosers that fail inspection or fail to operate during normal operations are tagged, bypassed and taken out of service. If a replacement is immediately available, BVES will schedule to it be replaced as soon as feasible. Otherwise BVES will order the replacement recloser and then schedule its replacement.

In the last 3 years, Bear Valley had 3 recloser failures. All of Bear Valley's service area is in the HFTD. There are approximately 24 reclosers in the system. Failure rate is 12.5%. The failures were associated with older oil filled reclosers, which are systematically being replaced; therefore, the failure rate is expected to significantly decrease.

Bear Valley has not experienced any ignitions from this equipment.

8.4.9 Splices (Tracking ID: GD_1 & GD_3)

BVES rarely uses splices. As part of cover conductor installation and distribution pole replacement and reinforcement initiatives, splices are removed.

Splices are inspected as follows:

- Detailed asset inspections (GD_22)
- Patrol asset inspections (GD_23)
- UAV thermography asset inspections (GD_24)
- UAV photography/videography asset inspection (GD_25)
- 3rd Party Ground Patrol asset inspection (GD_26)

In the last 3 years, Bear Valley had 0 splice failures. All of Bear Valley's service area is in the HFTD. Failure rate is 0.0%.

Bear Valley has not experienced any ignitions from this equipment.

8.4.10 Transmission Poles/Towers

N/A. BVES does not own or operate any transmission assets.

8.4.11 Transformers (Tracking ID: GD_5)

BVES routinely maintains these electrical assets through standard transformer operations and maintenance practices to prevent ignition risk mainly due to catastrophic failure.

BVES has over 2,000 service transformers and performs the following operations and maintenance on them:

- Detailed asset inspections (GD_22) (visual inspection checking for oil leakage, casing bulging, casing corrosion and integrity)
- Patrol asset inspection (GD_23) (visual inspection checking for oil leakage, casing bulging, casing corrosion and integrity)
- LiDAR asset inspections (VM_4)
- UAV thermography asset inspections (GD_24)
- UAV photography/videography asset inspection (GD_25)
- 3rd Party Ground Patrol asset inspection (GD_26)

BVES has 18 substation transformers and performs the following operations and maintenance on them:

- Periodic oil samples and analysis
- Monthly GO 174 visual inspection (checking for oil leakage, casing bulging, casing corrosion and integrity) and recording of operating temperatures and oil level
- Periodic thermography (every 4 years)
- Periodic winding resistance tests (every 4 years)
- Current injection test (every 4 years)
- Insulation resistance test (every 4 years)
- Transformer turns ratio (every 4 years)
- Power factor testing (every 4 years)

Service transformers are replaced based on their condition as determined by the above operations and maintenance actions and if the load needs to be expanded on the transformer.

Similarly, substation transformers are replaced based on condition as determined by the above operations and maintenance actions and generally as part of a major substation upgrade project. BVES's preventative maintenance and replacement program is intended to replace transformers before they fail.

In the last 3 years, Bear Valley had 3 transformer failures. All of Bear Valley's service area is in the HFTD. There are approximately 2,000 transformers in the system. Failure rate is 0.15%.

Bear Valley has not experienced any ignitions from this equipment.

8.4.12 Non-exempt equipment

N/A. BVES does not have additional non-exempt equipment not already listed and addressed.

8.4.13 Pre-G0 95 legacy equipment

N/A. BVES does not have pre-GO 95 legacy equipment.

8.4.14 Other Equipment not listed

N/A. BVES does not have other equipment not already listed and addressed.

8.5 Quality Assurance and Quality Control

8.5.1 Overview, Objectives, and Targets

Table 8-3. Example of Grid Design, Asset Inspections, and Maintenance QA and QC Program Objectives and **Table 8-4. Example of Grid Design, Asset Inspections, and Maintenance QA and QC Activity Targets** provide an overview of each of Bear Valley's QA and QC activities for grid design, asset inspections and maintenance.

Table 8-3 Example of 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
Covered Conductor Replacement Project	GD_1 & GD_3	QC	Ensure that new construction meets BVES standards.
Tree Attachment Removal Project	GD_12	QC	Ensure that the tree attachment was removed and the new construction meets BVES standards.
Grid Design	GD_16	QA	Ensure that the correct material was used and that construction meets BVES standards.
UAV Thermography	GD_24	QA/QC	Ensure that the inspection findings are correct.
UAV HD Photography	GD_25	QA/QC	Ensure that the inspection findings are correct.

Third-Party Ground Patrol	GD_26	QC	Ensure that the inspection findings are correct.
Substation Inspection	GD_28	QA	Ensure that the inspections are being completed to BVES standards.
Detailed Inspection	GD_22	QA	To ensure that the field inspector is following BVES procedures for detailed inspections.
Patrol Inspection	GD_23	QA	To ensure that the field inspector is following BVES procedures for patrol inspections.

Table 8-4 Example of Grid Design, Asset Inspections, and Maintenance QA and QC Activity Targets

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
Covered Conductor Installation	Field	Circuit Miles	8	8	10	10	10	10	100%	N/A	90%	90%	90%
Tree Attachment Removal Project	Field	Asset Inspection	100	100	100	100	45	45	100%	N/A	90%	90%	90%
Grid Design	Desktop	Circuit Miles	8	8	10	10	10	10	100%	N/A	90%	90%	90%
UAV Thermography	Desktop/Field	Circuit Mile	205	205	205	205	205	205	100%	N/A	90%	90%	90%
UAV HD Photography	Desktop/Field	Asset Inspection	205	205	205	205	205	205	100%	N/A	90%	90%	90%
Third-Party Ground Patrol	Field	Asset Inspection	205	205	205	205	205	205	100%	N/A	90%	90%	90%
Substation Inspection	Field	Asset Inspection	156	156	156	156	156	156	100%	N/A	90%	90%	90%
Detailed Inspection	Desktop/Field	# of Field Inspector	1	1	1	1	1	1	100%	N/A	90%	90%	90%
Patrol Inspection	Desktop/Field	# of Field Inspector	1	1	1	1	1	1	100%	N/A	90%	90%	90%

8.5.2 QA and QC Procedures

Asset management to achieve properly operating equipment and facilities is vitally important for enhancing public safety and mitigating the threat of wildfire. Therefore, establishing a high performing asset management quality assurance (QA) and quality control (QC) program is a critically essential element of a successful asset management program that aims to assure intended contractors' scope of work outcomes and asset management continuous process improvement.

Bear Valley's asset QA/QC program includes the identification and actionable outcomes of deficiencies and inspection protocols executed in the field. The findings and lessons learned from such actions, including third-party evaluations, are incorporated into the training and applying lessons learned from third-party evaluations and inspections. The initiative establishes an audit process for the Bear Valley Field Inspectors to manage and oversee the work completed by employees or contractors, including packaging QA/QC information for input to decision-making and workforce management processes. This includes the identification of deficiencies and actionable outcomes to improve inspection protocols executed in the field. This supports improvement of work outcomes, training of personnel involved in asset management, and applying lessons learned from internal and external evaluations and audits.

Covered Conductor Installation QC

BVES field inspector quality checks 100% of all covered conductor installation work throughout the service territory. The field inspector goes into the field with the construction plans and ensures that the construction was completed to BVES standards. If any issues are found during the QC inspection, the field inspector will immediately alert management and engineering and initiate an action to resolve the issue.

Bear Valley's engineering group also completes a quality assurance review of all the work orders from the covered conductor installation. The engineering department looks at the material list, as-built drawings, and photographs of the construction work to ensure the work was per the specifications called out by Bear Valley's standards for the work.

Tree Attachment Removal QC

BVES field inspector conducts quality checks on 100% of the tree attachment removal work throughout the service territory. The field inspector goes into the field with the construction plans and ensures that the construction was completed to BVES standards. If any issues are found during the QC inspection, the field inspector will immediately alert management and engineering will take action to resolve the issue.

Bear Valley's engineering group also completes a quality assurance review of all the work orders from the covered conductor installation. The engineering department looks at the material list, as-built drawings, and photographs of the construction work to ensure the work was per the specifications called out by Bear Valley's standards for the work.

Grid Design QA

The engineering group conducts the QA for all grid design work. Once construction is reported completed and the QC by the field inspector in the field is completed, all the records are given to the engineering group. The engineering group takes the as-built drawings, completed work photographs, and material sheets and conducts an analysis. This analysis is looking for discrepancies between the three documents. If there is a discrepancy of the equipment in the field, the field inspector will be notified immediately to resolve the issue. If there is an administrative discrepancy, the documentation issue will be resolved by engineering as applicable. This QA process is another safeguard to help ensure the work was completed to the required specifications, the correct material and equipment was installed, and the documentation of the complete work is accurate.

Asset Inspection QA and QC

Beginning in 2026, an annual QA audit of each asset inspection includes a 100% review of the asset inspection results. All asset inspection discrepancies are field checked. Additionally, a completeness check is performed to ensure the inspection included all of the facilities designated to be inspected. An audit pass rate of 90% is designated. Scores below 90% indicate an inspection process problem. If the score is below 90%, the root causes are investigated by the Wildfire Mitigation & Reliability Engineer and Utility Engineer and Wildfire Mitigation Supervisor and they are addressed with the persons performing the inspection. The failing inspections are paused until the issues are resolved. Also, depending on the severity of the issues, all or part of the inspection may be directed to be conducted again by the Wildfire Mitigation & Reliability Engineer.

QA/QC of distribution Detailed Inspections (GD_22) and Patrol Inspections (GD_23) conducted by Bear Valley's Field Inspector will include a supervisor's review and assessment of 100% of the findings identified during inspection. This will be conducted within 1 month of the inspection. The results of the review and assessment will be documented. In addition, each year 5% of the inspected facilities will be checked by a qualified inspector other than the person performing the original inspection as a QC check on these inspections. A pass rate of 90% is designated for these checks. If the checks result in a score below 90%, the root causes are investigated by the Wildfire Mitigation & Reliability Engineer and Field Operations Supervisor and they are addressed with the Field Inspector. The failing inspections are paused until the issues are resolved. Also, depending on the severity of the issues, all or part of the inspection may be directed to be conducted again by the Wildfire Mitigation & Reliability Engineer.

These changes will track pass/fail audit results, which will be communicated back to inspectors. Trends will be monitored and appropriate training will be delivered either individually or through annual refresher trainings administered to all qualified inspectors.

UAV Thermography (Tracking ID: GD_24)

BVES conducts a combination of quality assurance and quality checks on 100% of findings created by the UAV Thermography inspection. Once the data is delivered by the contractor, a quality assurance desktop review is conducted on all of the findings. Once the QA portion is completed the field inspector is sent into the field to conduct a visual QC to ensure that all findings are investigated and remediated. All of the findings sent to Bear Valley are QA/QC'd by Bear Valley's engineering/operations personnel. Any QA/QC discrepancies are sent to the contractor for further resolution and training.

UAV HD Photography/Videography (Tracking ID: GD_25)

BVES conducts a combination of quality assurance and quality checks on 100% of findings created by the UAV Photography/Videography inspection. Once the data is delivered by the contractor, a quality assurance desktop review is conducted on all of the findings. Once the QA portion is completed the field inspector is sent into the field to conduct a visual QC to ensure that all findings are investigated and remediated. All of the findings sent to Bear Valley are QA/QC'd by Bear Valley's engineering/operations personnel. Any QA/QC discrepancies are sent to the contractor for further resolution and training.

3rd Party Ground Patrol (Tracking ID: GD_26)

Bear Valley quality checks 100% of findings created by the 3rd party ground patrol inspection. This QC is conducted by the Bear Valley field inspector. Any QA/QC discrepancies are sent to the contractor for further resolution and training.

Substation Inspection (Tracking ID: GD_28)

BVES conducts quality assurance checks on 100% of substation inspections. Once a substation is inspected, the reports are submitted to the Wildfire Mitigation and Reliability Engineer and reviewed to ensure that the inspector followed the appropriate BVES procedures. Any QA/QC discrepancies are reviewed with the substation technician for further resolution and training.

8.5.3 Sampling Plan

Due to the small size of its territory, BVES is able to QA/QC 100% of the work and inspections, Bear Valley does not establish a statistically driven sampling plan that establishes sample sizes. All of Bear Valley's assets are in the HFTD and given its small size, 100% inspection is achievable and reasonable. Bear Valley has found this to be the most effective way to conduct QA/QC on its grid design, asset inspections, and maintenance programs.

8.5.4 Pass Rate Calculation

BVES uses historical data to create the allowable pass rate for the grid design, asset inspections, and maintenance QA/QC program. BVES uses a pass rate of 90% on the following grid design, asset inspections, and maintenance QA/QC programs:

- Covered Conductor Replacement Project (GD_1 & GD_3)
- Tree Attachment Removal Project (GD_12)
- Grid Design (GD_16)
- UAV Thermography (GD_24)
- UAV HD Photography (GD_25)
- 3rd Party Ground Patrol (GD_26)
- Substation Inspection (GD_28)

All discrepancies found during QA/QC are documented and resolved including providing training and feedback to the parties involved in the discrepancy. Scores below 90% indicate an inspection process problem. If the score is below 90%, the root causes are investigated by the Wildfire Mitigation & Reliability Engineer and Utility Engineer and Wildfire Mitigation Supervisor and they are addressed with the persons performing the inspection, work, or maintenance. The failing inspections are paused until the issues are resolved. Also, depending on the severity of the issues, all or part of the inspection, work, or maintenance may be directed to be conducted again by the Wildfire Mitigation & Reliability Engineer or Utility Engineer and Wildfire Mitigation Supervisor.

8.5.5 Other Metrics

Bear Valley conducts cross checks across all of the different asset inspection programs as an additional QA/QC. The Wildfire Mitigation and Reliability Engineer reviews the findings from each of the asset inspections conducted and will question why some inspections identify certain findings and others did not. For example, if the UAV Photography/Videography inspection identifies discrepancies that were not identified in the 3rd Party Ground Patrol inspection, the Wildfire Mitigation and Reliability Engineer will pursue the reasons for the gap. Each inspection has unique capabilities but, in some instances, both inspections should pick up the discrepancy so this may be used as a QA/QC. Any issues are brought to the attention of the inspector for further resolution and training. These cross checks are to be documented by the Wildfire Mitigation and Reliability Engineer.

8.5.6 Documentation of Findings

New construction QC documents are documented on the work orders themselves in the field. Once the field inspector completes the QC all findings are then reported to the operations supervisor with the results. Grid design QA is completed by the engineering group by using the Bear Valley asset management application (PowerPlan). Work packages are audited by both engineering and accounting and then they are archived.

Asset inspections QA/QC findings are documented in spreadsheets. The spreadsheets are directly exported reports from the database in which the inspections were documented. The QC/QA inspector takes the spreadsheets and confirms all of the findings from the inspection. These spreadsheets are then returned to the Wildfire Mitigation and Reliability Engineer for an analysis and retention.

The Wildfire Mitigation and Reliability Engineer works with Engineering to assign a priority level and due date in accordance with GO 95 Rule 18 requirements. The work order is then assigned to Field Operations to perform the work. Once the work order is completed, the Wildfire Mitigation and Reliability Engineer updates the work order status in the data base.

Bear Valley is in the process of developing a standard quarterly management report by the end of Q2 2025 with the following information:

- 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

The report will be generated by the Wildfire Mitigation and Reliability Engineer and reviewed by the Utility Engineer and Wildfire Mitigation Supervisor and Field Operations Supervisor.

8.5.7 Changes to QA and QC Since Last WMP and Planned Improvements

Current plans are to implement asset inspection QA/QC changes in 2026 as discussed in section 8.5.2 for detailed and patrol inspections. Bear Valley will monitor the results of its asset management QA/QC programs and implement improvements as warranted. Bear Valley will also exchange information with other utilities to determine best practices in asset management QA/QC for consideration in Bear Valley's program.

8.6 Work Orders

BVES follows General Order 95 (GO 95) Rule 18 requirements in managing and prioritizing open work orders. Work Orders include priority levels and associated timeframes for completion in accordance with GO 95 Rule 18 (e.g., Level 1, 2, or 3). BVES identifies work orders through its formal inspection programs and as identified conditions by service crews, supervisors, and call-ins. The deficiencies are input into an asset enterprise system (BVES utilizes iRestore) where a work order number is created.

Qualified BVES maintenance staff and contractors apply a level of severity in accordance with GO 95 Rule 18 and the iRestore program applies the corresponding timeframe for the remediation to be accomplished. If the repair is simple and does not require engineering design package (e.g., missing signage or visual strips), a Service Crew will be tasked to complete the work order, typically the same day. If the repair requires engineering design (e.g., pole replacement), the work order goes to the engineering planning group to have a design package created, but the situation will be at least mitigated down from a Level 1. Once a design package is developed, the package is provided to Field Operations and a construction crew is assigned to the work order to complete the required remediation.

BVES prioritizes open work orders first by level of severity defined by GO 95 Rule 18. Level 1 findings are addressed immediately by either completely remediating the issue or by making minor repairs to reclassify the issue to a Level 2 or level 3. Level 2 findings are assigned a timeframe of six months if in the HFTD Tier 3 area or twelve months if in the HFTD Tier 2 area. All Level 3 work orders are to be repaired within sixty months of being identified. BVES also prioritizes work orders within each level by HFTD. For example, HFTD Tier 3 Level 3 work orders have a higher priority over other areas. Finally, BVES priorities work orders within each level and HFTD area by higher risk circuits per BVES's the Fire Safety Circuit Matrix described in Section 6.2. For example, Level 2 work orders within the HFTD 2 area are prioritized based on the level of risk circuits per BVES's Fire Safety Matrix. As BVES implements it's Technosylva FireSight Risk Model, the model will be used in place of the Fire Safety Circuit Matrix to prioritize work orders.

At the time of this WMP submittal, BVES does not have any past due work orders. Therefore, Bear Valley does not have any information for **Table 8-5. Number of Past Due Asset Work Orders Categorized by Age** and **Table 8-6. Number of Past Due Asset Work Orders Categorized by Age for Priority Levels**.

Table 8-5 Number of Past Due Asset Work Orders Categorized by Age

HTFD Area	0-30 Days	31-90 Days	91-180 Days	181+ Days
Non-HFTD	0	0	0	0
HFTD Tier 2	0	0	0	0
HFTD Tier 3	0	0	0	0

Table 8-6 Number of Past Due Asset Work Orders Categorized by Age for Priority Levels

Priority Level	0-30 Days	31-90 Days	91-180 Days	181+ Days
Priority 1	0	0	0	0
Priority 2	0	0	0	0
Priority 3	0	0	0	0

Any past due work orders are immediately prioritized for correction. Work orders approaching their due date, or past due work orders are automatically flagged to BVES maintenance supervisors by the enterprise system. Other considerations in assigning work orders to crews are the work order age and grouping orders geographically together. For example, if a crew is working on a higher priority work order, lower priority work orders on the same facility would also be assigned to the crew so that they may be corrected while the crew is on site.

If a backlog of work orders coming due or even past due were to develop, BVES will develop a plan of action to gain control of the work orders as follows:

- First, BVES would prioritize completing the backlog with internal crew resources or augmenting with contracted crews.
- Second, BVES management will analyze the root causes contributing to the backlog developing and initiate corrective action to address the root causes.

8.7 Grid Operations and Procedures

8.7.1 Equipment Settings to Reduce Wildfire Risk

This section discusses Protective Equipment and Device Settings (PEDS) and Automatic Recloser (AR) settings. Bear Valley does not have settings of other emerging technologies (e.g., rapid earth fault current limiters).

Understanding the electric system load/demand allows Bear Valley to create an operating mode optimized for two types of operations: (1) safety and reliability and (2) wildfire prevention during high-risk periods. It should be noted that wildfire prevention measures during high fire risk weather conditions override reliability optimization regardless of season or system demand.

8.7.1.1 Protective Equipment and Device Settings

PEDS are advanced safety settings implemented by electric investor-owned utilities (IOUs) on electric utility power lines to reduce wildfire risk. PEDS are commonly known as “fast trip” settings and programs, which are utility programs intended to reduce wildfire risk by significantly increasing the sensitivity of protective devices and equipment that trigger automatic outages when a fault is detected. These programs are commonly referred to as Enhance Powerline Safety Settings (EPSS).

BVES operates its protection devices on the sub-transmission and distribution systems with fast curve trip settings (fast curve as provided by the manufacturer) for all operations all the time. The percentage of time Bear Valley has its protection devices on fast curve trip setting is 100 percent. All of Bear Valley's circuits are in the HFTD. This fast curve policy at Bear Valley has been in place for over 20 years. Bear Valley has not experienced an ignition in over 20 years.

The need for BVES to operate on fast curve trip settings is related to ensuring the reliability of the BVES system due to the Southern California Edison (SCE) power supply lines. BVES's 34.5kV sub-transmission system is fed by SCE's sub-transmission systems at 34.5kV at two delivery points. If BVES were to adjust its fast curve trip settings to slower trip curve settings and therefore, allow SCE devices to trip prior to BVES devices, then when a localized fault in the BVES system occurs, it would cause a loss of supply to the entire service area instead of limiting it to the group of assets associated with the localize fault. Such a scenario would significantly increase the size of outages in the BVES service area for small, localized faults.

It should be noted to avoid confusion, unlike other utilities that have established "fast trip settings", BVES is using the fast curve setting recommended by the device manufacturer. This is different than setting the trip values to a fixed set current value (typically about 120-150% of normal load) at a fast trip speed (typically one tenth of a second). The manufacturer's fast curve settings are a traditional time-current curve in shape.

Table 8-7. Top Ten Impacted Circuits from Changes to PEDS in the Past Three Years provides the top ten impacted circuits due to PEDS (fast curves trip settings at BVES). Since BVES does not change PEDS (as discuss above, BVES uses fast curve trip settings all year round), the data in the table is all year-round data for the past three years (2022 to 2024).

Table 8-7 Top Ten Impacted Circuits from Changes to PEDS in the Past Three Years

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 (minutes)	Cumulative number of customers impacted by outages
Baldwin	Baldwin	8.94	8	424	116359
Shay	Shay	17.17	3	150	31599
Interlaken	Interlaken	6.45	4	329	9325
Clubview	Clubview	10.18	2	478	8895
Erwin Lake	Erwin Lake	21.83	4	333	8618

Goldmine	Goldmine	13.2	3	368	7371
North Shore	North Shore	15.83	3	262	5920
Sunset	Sunset	10.67	1	341	5514
Boulder	Boulder	17.23	6	356	5025
Radford	Radford	3	2	50	3437

Bear Valley conducted discussions with Pacific Gas and Electric (PG&E) and San Diego Gas and Electric (SDGE) subject matter experts regarding EPSS to examine their programs and learn from their experiences in this area.

In 2024, Bear Valley engaged an expert power distribution consultant firm to perform an evaluation of the Bear Valley's device setting policy and provide recommendations to improve settings to reduce the probability of ignitions. The consultant completed the study of BVES's protective settings on 10 sample circuits (3 sub-transmission circuits and 7 distribution circuits) at the end of January 2025. Key findings are:

- Not all protection devices have 100% coverage for phase and ground faults, which results in long clearing times at the end of zones of protection.
- To have a protection scheme that will cover 100% of the required circuit the settings will need to be set more sensitively to extend the circuit coverage.
- The study proposes an EPSS philosophy as follows:
    - The goal of EPSS protection is to trip and clear faults as fast as possible on the entirety of the protected circuit. To do so, this protection sacrifices circuit coordination in favor of sensitivity and fast tripping.
    - The EPSS protection should be set as follows:
        - <u>Reclosing</u>: All reclosing attempts disabled. Devices will be single trip to lockout.
        - <u>Phase Sensitivity</u>: 1.5 times peak loading ≤ Minimum Phase Trip (Pickup) < EOLLL /2 (50% protection reach margin). Use Phase Fast curve = TCC 101.
        - <u>Ground Sensitivity</u>: 1.5 times peak load imbalance ≤ Minimum Ground Trip (Pickup) < EOLSLG /3 (33% protection reach margin). If load imbalance data is not available: Ground minimum trip > 30% of historical peak load phase current imbalance at the protection device. Ground Fast curve = TCC 101.
        - Use of the 101 time current curve ensures faults should clear within 12.0 cycles (0.2 seconds).

- The study proposes the following implementation strategy:
    - To improve circuit coverage for fast tripping and sensitivity, implement the following device setting changes:
        - 1) Enable ground overcurrent elements in any protection devices where the protection is available but turned off. This should be enabled

on all 4.16 kV distribution circuits. This will allow much greater sensitivity for single line to ground faults.
        - 2) Standardize and update fast curves across all 4.16kV devices. In "EPSS" setting profiles, for the initial fast trip update the curves to the standardized TCC 101 curve. Special focus should be given to those devices that are presently using SEL U5 or inverse curves.
        - 3) While updating the fast curves, it would be most efficient to also re-evaluate and update pickup settings per the criteria contained in the EPSS Philosophy.
        - 4) Ensure reclose attempts are disabled in EPSS setting profile.
    - Having pickup setting flexibility and ground overcurrent protection is key for EPSS. Oil reclosers may not offer these capabilities. It is recommended to replace any oil recloser units with electronically controlled reclosers.
    - For instances where device pickups cannot satisfy both protection reach margins and load security margins, consider installing an additional downline series recloser. The new recloser should shorten the zone of protection bringing the EOL fault location closer. The new recloser should also see a smaller peak load current, allowing it to have a more sensitive pickup.

Based on the results of the study, Bear Valley is conducting the following:

- Developing an EPSS operational policy. This is to be completed by end of Q2 2025.
    - Which circuits should have EPSS capability?
    - When should EPSS be invoked (e.g., when FPI is "High" or higher)?
    - How is EPSS implemented (e.g., operational direction and connectivity to devices)?
- Developing a circuit-by-circuit plan to implement EPSS recommendations in coordination with the EPSS operational policy.
    - For each circuit identify any equipment, hardware, software, and/or connectivity gaps to implementing EPSS and develop a plan to close the gaps on a risk-based priority.
    - For each circuit develop EPSS settings for protection devices on the circuit.
    - This planning action is to be completed by the end of Q3 2025.
- EPSS Implementation:
    - Update internal procedures and conduct training with staff on EPSS policy.
    - For circuits that are ready to implement EPSS, when conditions warrant, implement EPSS.
    - For circuits requiring equipment, hardware, software, and/or connectivity to implement EPSS, pursue upgrading these circuits on a risk-based priority schedule and as each circuit becomes EPSS capable, implement EPSS when conditions warrant EPSS.

    - Implementation should begin in Q4 2025 and the goal is to be fully implemented by the end of 2027.

8.7.1.2 Automatic Recloser Settings

An automatic recloser (AR) is an automatic, high-voltage electric switch with protective settings capable of detecting faults. When a fault is detected by the switch, it opens to remove power to the circuit to prevent equipment and property damage and prevent ignitions. After a set period of time (such as 5-30 seconds), a recloser automatically tests the electrical line to determine whether the fault has been removed. If the problem was only temporary, then the recloser automatically resets itself and restores the electric power. Reclosers can be programmed to test several times (typically 3 times). Reclosers are used throughout the power distribution system, from the substation to residential utility poles. They range from single-phase reclosers used on downstream of power lines, to larger three-phase reclosers used in substations and on high-voltage power lines. In overhead electrical systems, a majority of the faults that occur are intermittent or transient (e.g., lightning strike, surges, objects contacting the lines, etc.). Therefore, when an AR opens on fault, for the purpose of increased reliability, it is beneficial to test the circuit after a brief period to see if the fault cleared. The automatic function of an AR reduces the number of sustained outages and improves customer reliability. The reclosing function, however, implicates some degree of ignition risk because additional energy can be released if a fault persists, such as if a branch is laying across the lines. Some AR test at reduced current (about 10%) to mitigate the risk of ignition. These are Pulse Conditioned ARs. ARs can be set to “Manual” or “One-shot”, which disables the automatic reclosing function. Underground circuits are not likely susceptible to intermittent faults and reclosing into an existing fault may result in further damage; therefore, there is no reliability benefit to reclosing on an underground circuit. A similar discussion follows on overhead circuits with covered conductor installed. Intermittent faults on covered conductors are also less likely; therefore, reclosing is not advisable.

Bear Valley’s entire service area is within the HFTD. From approximately mid-November to April, Bear Valley will generally experience winter storms with a seasonal average of approximately 58 inches of snow. Therefore, during the winter weather the threat of wildfire is less likely and reliability of power to customers during freezing weather is of concern.

Based on the above, Bear Valley’s reclosing posture is as follows:

- All Year Round:
    - ARs to underground circuits are placed in “Manual” mode of operation (e.g., they will not shut and test upon detecting a fault).

  - ARs to overhead circuits that are 70% or more covered conductors are placed in “Manual” mode of operation (e.g., they will not shut and test upon detecting a fault).
  - ARs that are not connected to the SCADA network shall be placed in “Manual” mode of operation (i.e., they will not shut and test upon detecting a fault).
  - Fuse TripSavers that are not connected to the SCADA network shall be placed in “Manual” mode of operation (i.e., they will not shut and test upon detecting a fault).
- April 1st to October 31st:
  - All ARs are placed in “Manual” mode of operation (e.g., they will not shut and test upon detecting a fault).
  - All Fuse TripSavers shall be placed in “Manual” mode of operation (i.e., they will not shut and test upon detecting a fault)
- March 31st to November 1st:
  - SCADA connected ARs may be placed in “Automatic” mode of operation (e.g., three trips to lockout) at the direction of the Field Operations Supervisor when the FPI is “Moderate” or lower.
  - SCADA connected Fuse TripSavers may be placed in “Automatic” mode of operation (e.g., three trips to lockout) at the direction of the Field Operations Supervisor when the FPI is “Moderate” or lower.

If an AR is Pulse Condition capable and is placed in “Automatic”, the Pulse Condition feature shall be enabled.

Bear Valley has engaged an expert power distribution consultant firm to study its AR policy and to provide further recommendations to enhance public safety. This study is expected to be completed by the end of 2025.

8.7.1.3 Settings of Other Emerging Technologies

Bear Valley does not have settings of other emerging technologies (e.g., rapid earth fault current limiters).

8.7.2 Grid Response Procedures and Notifications

Field Operations staff are alerted to outages, faults, ignitions, or other issues detected on its grid that may result in a wildfire through a variety of means, including:

- SCADA system alert (switches, fault indicators, capacitor banks, Fuse TripSavers).
- Fault Localization Isolation System Restoration (FLISR) system alert – system of switches on the sub-transmission system that communicate, locate fault, and isolate the fault while restoring power to unaffected areas automatically.
- Circuit meter alert (Expert Power) – circuit level metering (each phase) that records and alerts power outages.

- Online Diagnostic System alert.
- iSIU system alert (Camera alert).
- Customer call center reports of outages and issues.
- iRestore application report from local Fire and Sheriff departments.

Information collected provides a basic understanding of the issue and this information is relayed to the Field Operations Service Crew (during normal working hours) or the Dutyman (afterhours) who's priority is to investigate any outage or issue in the field. These crews investigate outages in the field to determine the extent of the damage. Locating the issue is achieve by a variety of methods, including:

- SCADA information
- FLISR information
- Circuit meter alert (Expert Power)
- Outage Management System algorithm
- Fault Indicators in the field
- Customer call center reports of outages and issues.
- iRestore application report from local Fire and Sheriff departments.
- Patrols in high probability areas based on above information

This information is quickly communicated to management which determines the personnel, equipment and outside sources needed to optimize recovery times. As necessary, BVES will conduct work with associated fire risk by de-energizing work areas. BVES will notify the Big Bear Fire Department (BBFD) and/or Cal Fire if any ignitions or wildfires are detected. As recovery activities progress, the field crews communicate with management who will quickly adjust recovery resources and activities, as required.

Any significant outage or after-hours outage effecting more than 25 customer meters is also communicated via text messages to the BVES "Internal PSPS List" which includes management, field and other key personnel involved with responding to emergency situations.

Response priorities are based on customer impacts unless an ignition, fire, or other safety issue is present, in which case those incidents would take priority. If no safety issue is present, critical public infrastructure is given the highest priority, after which resources are deployed to the incidents with the largest customer impacts.

Bear Valley will expand resources available to minimize response times based on Fire Potential Index. During days with an FPI "Very High" or "Extreme", staffing is increased around the clock.

8.7.3 Personnel Work Procedures and Training in Conditions of Elevated Fire Risk

Each day, a service area map displaying FPI and ignition risk for the sub-transmission and distribution system is circulated to the Engineering, Field Operations, Customer Service, and management. Bear Valley has protocols in place that require on days where FPI is “High” or higher, employees and contractors are to:

- Cease using any spark-producing tools and equipment for circuits under consideration or in scope.
- Cease vegetation management work for circuits under consideration or in scope.
- Cease “high risk” energized line work for circuits under consideration or in scope.

Bear Valley’s small size allows the workforce to pivot to low-risk work on high fire threat days or conduct a training day for its staff. This is true for its contracted power line staff as well who have a detailed program and checklist to outline necessary precautions based on the Fire Index Rating (FIR). BVES and its contractors can easily pivot to low-risk activities on short notice due to its small size. For example, if a high fire threat day occurs with little notice, BVES can pivot from covered wire or pole replacement work to other de-energized work or to training, which it has at the ready.

Bear Valley’s vegetation management contractor has protocols in place for high fire threat weather. For example, when fire threat conditions exist, the vegetation contractor will:

- Evaluate the weather conditions to ensure they are safe to work in.
- A Dedicated Fire Watch must be assigned to the jobsite.
- There must be a trailer-mounted water tank or alternative water delivery method at the jobsite (120 gallons with 200 feet of hose).
- No chainsaw operations allowed – only hand saw use permitted.

Additionally, on a “High” or higher FPI day, if Bear Valley can de-energize an area without impact to customers, Bear Valley may opt to conduct work by de-energizing work areas as applicable to remove the ignition risk from the work. If de-energization is not feasible, the work will be rescheduled to a lower risk day.

BVES will notify the BBFD and/or Cal Fire if any ignitions or wildfires are detected.

BVES will continue to evaluate its policies to not conduct certain work that produces sparks or has the potential to produce sparks on high fire threat days. Based on experience, lessons learned, and techniques other utilities are utilizing, BVES will frequently evaluate its approach and is open to making adjustments if there is a compelling reason to do so.

8.8 Workforce Planning

The following is 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

The following are the key roles, qualifications, and training for personnel involved in asset inspections.

Field Inspector (BVES Employee)

Minimum Qualifications for Target Role: Three years of Journeyman Lineman or above experience. IBEW Journeyman Lineman status in good standing. Demonstrated knowledge and proficiency in GO 95 and GO 128. Experience inspecting overhead and underground facilities. Class C California Driver's License.

Special Certification Requirements: Journeyman Lineman

Light Crew Foreman (BVES Employee)

Minimum Qualifications for Target Role: Three years of experience as a Journeyman Lineman or Service Crew Foreman. IBEW Journeyman Lineman status in good standing. Knowledge of: (1) Methods, materials, and tools used in electrical overhead and underground construction, maintenance, and repair work; (2) Principles of electrical theory as applied to electrical circuits and wiring systems, GO 95 and 128, service requirements and all applicable codes, accident prevention rules and ordinances; and (3) Occupational hazards and standard safety precautions necessary in work. Class A California Driver's License.

Special Certification Requirements: Journeyman Lineman

Service Crew Foreman (BVES Employee)

Minimum Qualifications for Target Role: Three years of experience at the journey level in construction, maintenance, and repair of both overhead and underground electrical systems. IBEW Journeyman Lineman status in good standing. Knowledge of: (1) Methods, materials, and tools used in electrical overhead and underground construction, maintenance, and repair work; (2) Principles of electrical theory as applied to electrical circuits and wiring systems, GO 95 and 128, service requirements and all applicable codes, accident prevention rules and ordinances; (3) Inspection program requirements of GO 165 and GO 174; and (4) Occupational hazards and standard safety precautions necessary in work. Class A California Driver's License.

Special Certification Requirements: Journeyman Lineman

Substation Technician (BVES Employee)

Minimum Qualifications for Target Role: Minimum five (5) years' experience observing and operating substation equipment. Journeyman Lineman certification is a plus. Demonstrated ability to read and understand electrical system drawings and substation equipment technical manuals. Sound knowledge of: (1) Methods, materials, and tools used in electrical distribution system substation construction, operations, maintenance, diagnostic, and repair work; (2) Principles of electrical theory as applied to distribution system substations and grid equipment (34.5 kV and 4.160 kV); (3) Inspection program requirements of GO 174; (4) SCADA and electric utility GIS systems; and (5) IEEE-SA - National Electrical Safety Codes (NESC) as they pertain to electrical distribution substations and grid equipment. Class C California Driver License.

Special Certification Requirements: None specified. Journeyman Lineman certification a plus.

Utility Systems Specialist Inspector/Lead Inspector (Contractor)

Minimum Qualifications for Target Role: Overhead Distribution and/or Transmission distribution inspection experience (2-year min).

Identification of all overhead equipment.

Current Driver License.

Computer and GIS mapping experience.

Special Certification Requirements: NESC and ANSI Inspection experience (1-year min). Red Cross FA/CPR Certified. Wildfire Training.

Geospatial Project Manager (Contractor)

Minimum Qualifications for Target Role: 8 years of GIS and Remote Sensing Experience. 5 years or more in a Supervisory Role. Advanced Knowledge of LiDAR Sensors and Data. Advanced GIS Skills and Problem Solving.

Special Certification Requirements: Geospatial Information Systems Professional (GISP). ASPRS Certified Mapping Scientist, LiDAR.

Geospatial Lead Analyst (Contractor)

Minimum Qualifications for Target Role: 8 years of GIS and Remote Sensing Experience. Strong Quality Control and Detail. Advanced Knowledge of LiDAR Sensors and Data. Advanced GIS Skills and Problem Solving.

Special Certification Requirements: ASPRS Certified Remote Sensing Technologist.

Geospatial Technician (Contractor)

Minimum Qualifications for Target Role: Solid Understand of GIS and Remote Sensing Science. Strong Attention to Detail. Strong Computer Skills. Work Independently.

Special Certification Requirements: None specified.

Grid Hardening

The following are the key roles, qualifications, and training for personnel involved in grid hardening.

Utility Engineer & Wildfire Mitigation Supervisor (BVES Employee)

Minimum Qualifications for Target Role: Bachelor's Degree in an engineering field or a technical discipline required.

Eight years of planning, construction, or engineering experience including four years of administrative and supervisory experience. Utility experience preferred. Work experience in an area with strong compliance regimes. Experience interacting with utility regulators and knowledge of regulatory processes preferred. Knowledge of overhead and underground line construction, substations, transformation, cabling, voltage drop, circuit protection and protection coordination, rules, rates and schedules, Company policies and procedures, service requirements, material management, electrical codes, budgeting and electrical theory and application.

Special Certification Requirements: Professional Engineer license in California required. If not held, must obtain within 2 years of employment.

Field Operations Supervisor (BVES Employee)

Minimum Qualifications for Target Role: Associate degree (Bachelor's preferred) in electrical engineering and construction management or related field or fifteen (15) years of experience in supervising line operations. Seven years of experience in line operations working under a collective bargaining agreement or equivalent combination of experience and education required. Thorough knowledge of GO 95/165 and Construction Methods.

Special Certification Requirements: None Specified.

Electric Distribution Systems Engineer

Minimum Qualifications for Target Role: Bachelor's Degree in Electrical Engineering, or related field. Strong experience with overhead and underground distribution and substation design. Knowledge of SCADA and automated grid systems are highly desirable. Excellent knowledge and strong experience in working in a highly regulated environment and working with a large number of agencies such as: US Forest Service, US Bureau of Land Management, US Fish and Wildlife Service, California Department of Fish and Game, California Division of Occupational Safety and Health (DOSH, also known as Cal/OSHA), California Department of Transportation (Caltrans), Department of Transportation (DOT), State Water Resource Control Board, California Environmental Protection Agency (EPA), and South Coast Air Quality Management District (SCAQMD). Experience with California Environmental Quality Act (CEQA) process. Experience and working knowledge of CPUC General Orders 95, 128, 165 and 174.

Special Certification Requirements: Professional Engineer's (PE) license in the California is strongly desired. Note, that if the applicant does not have a PE in California, the applicant will be required to obtain a California PE license within 12 months of employment at BVES, Inc. in this position.

Project Coordinator (BVES Employee)

Minimum Qualifications for Target Role: Associates or bachelor's degree preferred. Project Management course work and Project Management Professional (PMP) certification preferred. Four years of experience in construction projects including demonstrable project management experience. Utility Planning Certification preferred.

Special Certification Requirements: None Specified.

Utility Planner I (BVES Employee)

Minimum Qualifications for Target Role: Bachelor's degree in Engineering or successful completion of a Utility Planning Certification required. Minimum of 2 years utility or comparable construction planning experience performing duties such as estimating, planning, and electrical distribution design work.

Special Certification Requirements: None Specified.

Engineering Inspector (BVES Employee)

Minimum Qualifications for Target Role: Minimum three years of experience at an Engineering Technical position or equivalent in an electric utility working the area of distribution. Experience identifying in field electrical equipment. Experience in distribution facility overhead design. Demonstrated Experience in AutoCAD design software and experience with GIS software (desired). Excellent understanding of the JPA process and paperwork.

Special Certification Requirements: None Specified.

Light Crew Foreman (BVES Employee)

Minimum Qualifications for Target Role: Three years of experience as a Journeyman Lineman or Service Crew Foreman. IBEW Journeyman Lineman status in good standing. Knowledge of: (1) Methods, materials, and tools used in electrical overhead and underground construction, maintenance, and repair work; (2) Principles of electrical theory as applied to electrical circuits and wiring systems, GO 95 and 128, service requirements and all applicable codes, accident prevention rules and ordinances; and (3) Occupational hazards and standard safety precautions necessary in work. Class A California Driver's License.

Special Certification Requirements: Journeyman Lineman

Service Crew Foreman (BVES Employee)

Minimum Qualifications for Target Role: Three years of experience at the journey level in construction, maintenance, and repair of both overhead and underground electrical systems. IBEW Journeyman Lineman status in good standing. Knowledge of: (1) Methods, materials, and tools used in electrical overhead and underground construction, maintenance, and repair work; (2) Principles of electrical theory as applied to electrical circuits and wiring systems, GO 95 and 128, service requirements and all applicable codes, accident prevention rules and ordinances; (3) Inspection program requirements of GO 165 and GO 174; and (4) Occupational hazards and standard safety precautions necessary in work. Class A California Driver's License.

Special Certification Requirements: Journeyman Lineman

Lineman (BVES Employee)

Minimum Qualifications for Target Role: Certified completion of a union or company recognized lineman apprenticeship training program. IBEW Journeyman Lineman status in good standing. Past experience in climbing wooden power poles and working on high voltage power lines. Knowledge of basic principles of electricity, current theory mathematics, GO 95 and 128 and all applicable codes, accident prevention orders and ordinances. Knowledge of methods, material and tools used in the construction, maintenance and repair of an overhead/underground transmission, distribution, and substation electrical system. Must possess or obtain within 6 months a valid Class A California Driver's License.

Special Certification Requirements: Journeyman Lineman

Substation Technician (BVES Employee)

Minimum Qualifications for Target Role: Minimum five (5) years experience observing and operating substation equipment. Journeyman Lineman certification a plus. Demonstrated ability to read and understand electrical system drawings and substation equipment technical manuals. Sound knowledge of: (1) Methods, materials, and tools used in electrical distribution system substation construction, operations, maintenance, diagnostic, and repair work; (2) Principles of electrical theory as applied to distribution system substations and grid equipment (34.5 kV and 4.160 kV); (3) Inspection program requirements of GO 174; (4) SCADA and electric utility GIS systems; and (5) IEEE-SA -

National Electrical Safety Codes (NESC) as they pertain to electrical distribution substations and grid equipment. Class C California Driver License.

Special Certification Requirements: None specified. Journeyman Lineman certification a plus.

<u>Risk Event Inspection</u>

The following are the key roles, qualifications, and training for personnel involved in risk event inspection.

Utility Engineer & Wildfire Mitigation Supervisor (BVES Employee)

Minimum Qualifications for Target Role: Bachelor's Degree in an engineering field or a technical discipline required. Eight years of planning, construction, or engineering experience including four years of administrative and supervisory experience. Utility experience preferred. Work experience in an area with strong compliance regimes. Experience interacting with utility regulators and knowledge of regulatory processes preferred. Knowledge of overhead and underground line construction, substations, transformation, cabling, voltage drop, circuit protection and protection coordination, rules, rates and schedules, Company policies and procedures, service requirements, material management, electrical codes, budgeting and electrical theory and application.

Special Certification Requirements: Professional Engineer license in California required. If not held, must obtain within 2 years of employment.

Field Operations Supervisor (BVES Employee)

Minimum Qualifications for Target Role: Associate degree (Bachelor's preferred) in electrical engineering and construction management or related field or fifteen (15) years of experience in supervising line operations. Seven years of experience in line operations working under a collective bargaining agreement or equivalent combination of experience and education required. Thorough knowledge of GO 95/165 and Construction Methods.

Special Certification Requirements: None Specified.

Electric Distribution Systems Engineer

Minimum Qualifications for Target Role: Bachelor's Degree in Electrical Engineering, or related field. Strong experience with overhead and underground distribution and substation design. Knowledge of SCADA and automated grid systems are highly desirable. Excellent knowledge and strong experience in working in a highly regulated environment and working with a large number of agencies such as: US Forest Service, US Bureau of Land Management, US Fish and Wildlife Service, California Department of Fish and Game, California Division of Occupational Safety and Health (DOSH, also known as Cal/OSHA), California Department of Transportation (Caltrans), Department of Transportation (DOT), State Water Resource Control Board, California Environmental Protection Agency (EPA), and South Coast Air Quality Management District (SCAQMD). Experience with California Environmental Quality Act (CEQA) process. Experience and working knowledge of CPUC General Orders 95, 128, 165 and 174.

Special Certification Requirements: Professional Engineer's (PE) license in the California is strongly desired. Note, that if the applicant does not have a PE in California, the applicant will be required to obtain a California PE license within 12 months of employment at BVES, Inc. in this position.

9. Vegetation Management and Inspections

9.1 Targets

9.1.1 Qualitative Targets

9.1.2 Quantitative Targets

Table 9-1 Vegetation Management Targets by Year (Non-inspection Targets) below provides the targets for the Vegetation Management and Inspection category (non-inspection initiatives).

Table 9-1 Vegetation Management Targets by Year (Non-inspection Targets)

Initiative	Quantitative or Qualitative	Activity (Tracking ID)	Previous Tracking ID, if applicable	Target Unit	2026 Target/Status	% Risk Reduction for 2026	2027 Target/Status	% Risk Reduction for 2027	2028 Target/Status	% Risk Reduction for 2028	Three-Year Total	Section; Page Number
Pruning and Removal	Quantitative	Fall-in mitigation and high-risk species (VM-8)	VM-10 & VM_12	# of trees remediated or removed to prevent fall-in	88	11.62%	88	11.62%	88	11.62%	216	9.3; p.201
Pruning and Removal	Quantitative	Clearance (VM-9)	VM-9	Circuit Miles Cleared	72	11.62%	72	11.62%	72	11.62%	216	9.3; p.201
Pole clearing	Quantitative	Pole clearing (VM- 10)	VM-7	# of Poles Cleared	70	4.34%	70	4.34%	70	4.34%	210	9.4; p.206
Wood and slash management	Qualitative	Wood and slash management (VM-11)	VM-8	Wood & slash removed per VM Contract	N/A	4.65%	N/A	4.65%	N/A	4.65%	N/A	9.5; p.207
Defensible space	Quantitative	Defensible space (VM-12)	VM-11	# of Substations Cleared	13	3.12%	13	3.12%	13	3.12%	39	9.6; p.208
Activities based on weather conditions	Qualitative	Activities based on weather conditions (VM-13)	VM-14	Review Vegetation Management Emergency Response Procedures Annually	N/A	1.22%	N/A	1.22%	N/A	1.22%	N/A	9.9; p.211
Post-fire service restoration	Qualitative	Post-fire service restoration (VM-14)	N/A	Review Post-fire service restoration procedures annually	N/A	3.12%	N/A	3.12%	N/A	3.12%	N/A	9.10; p.213
Quality assurance / quality control	Quantitative	Quality assurance/ quality control (VM-15)	VM-16	# of VM QCs Performed	72	3.12%	72	3.12%	72	3.12%	216	9.11; p.213

Work orders	Qualitative	Work orders (VM-16)	VM-17	90% or more of work orders completed on schedule for the year	N/A	3.12%	N/A	3.12%	N/A	3.12%	N/A	9.12; p.221
Workforce Planning	Qualitative	Workforce planning (VM-17)	VM-18	Evaluate annually workforce training and adequacy	N/A	3.12%	N/A	3.12%	N/A	3.12%	N/A	9.13; p.223
Integrated vegetation management	BVES does not have any programs under this initiative	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	9.13; p.223

Table 9-2, Vegetation Inspections and Pole Clearing Targets by Year below provides the targets for the Vegetation Management and Inspection category (inspection initiatives).

Table 9-2 Vegetation Management Inspection Frequency, Method, and Criteria

Activity (Program)	Tracking ID	Previous Tracking ID, if applicable	Target Unit	Cumulativ e (Cml.) Quarterly Target Year 1, Q1	Cml. Quarterly Target Year 1, Q2	Cml. Quarterly Target Year 1, Q3	Cml. Quarterly Target Year 1, Q4	Cml. Quarterly Target Year 2, Q1	Cml. Quarterly Target Year 2, Q2	Cml. Quarterly Target Year 2, Q3	Cml. Quarterly Target Year 2, Q4	Cml. Quarterly Target Year 3, Q1	Cml. Quarterly Target Year 3, Q2	Cml. Quarterly Target Year 3, Q3	Cml. Quarterly Target Year 3, Q4	% HFTD Covered in 2026	2026 Total	% Risk Reduction for 2026	% Risk Reduction for 2027	% Risk Reduction for 2028	Three-Year Total	Activity Timeline Target	Section; Page Number
Detailed Inspections	VM_1	VM_1	Circuit Miles Inspected	10	25	40	55	10	25	40	55	10	25	40	55	26.0%	55	5%	5%	5%	165	7 days	9.2.1; p.184
Patrol inspection	VM_2	VM_2	Circuit Miles Inspected	52	102	153	205	52	102	153	205	52	102	153	205	100%	205	4.65%	5%	4.7%	615	7 day	9.2.1; p.184
UAV HD Photography.Videography	VM_3	VM_3	Circuit Miles Inspected	0	0	205	205	0	0	205	205	0	0	205	205	100%	205	4.65%	4.65%	4.65%	615	30 day	9.2.1; p.184
LiDAR Inspection	VM_4	VM_4	Circuit Miles Inspected	0	0	205	205	0	0	205	205	0	0	205	205	100%	205	4.65%	4.65%	4.65%	615	30 day	9.2.1; p.184
Third-Party Ground Patrol	VM_5	VM_5	Circuit Miles Inspected	0	0	205	205	0	0	205	205	0	0	205	205	100%	205	4.65%	4.65%	4.65%	615	30 day	9.2.1; p.184
Substation Inspection	VM_6	VM_6	# of Substations Inspected	36	72	108	144	36	72	108	144	36	72	108	144	100%	144	4.65%	4.65%	4.65%	432	30 day	9.2.1; p.184
Satellite imagining inspection	VM_7	VM_19	Inspection of Entire Service Area	0	0	1	1	0	0	1	1	0	0	1	1	100%	1	4.65%	4.65%	4.65%	3	30 day	9.2.1; p.184

9.2 Vegetation Management Inspections

Table 9-3 Vegetation Management Inspection Frequency, Method, and Criteria provides an overview of Bear Valley's inspection activities.

Table 9-3 Vegetation Management Inspection Frequency, Method, and Criteria

Type	Inspection Activity (Program)	Area Inspected	Frequency
Distribution	Detailed Inspection	Entire Service Area	Five-year cycle of entire service area. Higher risk circuits every 3 years.
Distribution	Patrol inspection	Entire Service Area	Annual survey of entire service area
Distribution	UAV HD Photography / Videography	Entire Service Area	Annual survey of entire service area
Distribution	LiDAR Inspection	Entire Service Area	Annual survey of entire service area
Distribution	Third-Party Ground Patrol	Entire Service Area	Annual survey of entire service area
Distribution	Substation Inspection	Entire Service Area	Monthly inspections of all in-service substations
Distribution	Satellite imagining inspection	Entire Service Area	Annual survey of entire service area

9.2.1 Detailed Inspection (Tracking ID: VM_1)

9.2.1.1 Overview and Area Inspected

Bear Valley conducts detailed inspections in accordance with GO 165, which mandates detailed inspections on all overhead facilities at a minimum of once every 5-years. Bear Valley conducts detailed inspections on every asset in the entire service territory at a minimum of every 5 years. Additionally, using a risk prioritized methodology, higher risk circuits (bare conductors in higher risk areas) are detailed inspected more frequently. All of Bear Valley's service area is in the HFTD.

9.2.1.2 Procedures

The BVES Inspection Plan is intended to promote safety and circuit reliability, minimize service interruption, and reduce the risk of fire through routine visual inspection of facility conditions. The inspection focus is on ensuring compliance with GO 95 and GO 165 requirements. In these Detailed Inspections, vegetation and individual trees in the rights-of-way are carefully examined, visually, and discrepancies are recorded. This inspection is thorough and is more time consuming than Patrol Inspections. Individual pieces of equipment and structures are carefully examined to determine the condition of each rated and recorded component and vegetation clearances to bare conductor and other components. Identifying vegetation encroachments to minimum clearance requirements (as established by GO 95 or BVES, whichever is greater) is the first step in correcting such occurrences, which in turn reduces the probability of ignitions due to vegetation contacting bare conductors.

Inspection intervals and reports comply with the requirement specified in GO 165. BVES's Inspection Program requires overhead facilities to be patrol inspected each year. A "detailed inspection" is a more careful visual exam of individual pieces of equipment. The inspector records the results of the visual examinations and rates the condition of the vegetation. These inspections are designed to identify any vegetation encroachment inside of BVES's minimum clearance standards or encroachment that will lead to violation of minimum clearance standards before the next scheduled vegetation clearance crew visit. These encroachments have the potential to spark and ignite a wildfire. Detailed Inspections are a critical element in mitigating the risk of wildfire caused by electric utility facilities.

BVES's Field Inspector performs the Detailed Inspections. The Field Inspector is required to be a Journeyman Lineman experienced in inspection of electric transmission and distribution facilities and power lines. The Field Inspector works closely with the contracted Forester to ensure he is equipped to properly inspect vegetation around power lines.

Detailed Inspection findings are rated in accordance with GO 95 Rule 18 (level 1, 2, or 3) and entered in the distribution inspection GIS database. Level 1 findings are reported immediately to the Field Operations Supervisor who will direct corrective action as soon as possible to resolve the issue or reduce its severity to Level 2 so that more time is available to perform permanent corrective action.

The Wildfire Mitigation and Reliability Engineer reviews the results of detailed inspections and assigns corrective action to the vegetation clearance crews. Additionally, the Wildfire Mitigation and Reliability Engineer reviews the results of detailed inspections as well as other vegetation inspections to determine if there are systemic issues that must be addressed. Finally, the results of detailed inspections are cross checked against other vegetation inspections to evaluate the quality and effectiveness of each inspection type.

9.2.1.3 Clearance

GO 95, Rules for Overhead Electric Line Construction, Rule 35 identifies the minimum radial clearances for vegetation around power lines. In accordance with GO 95 Appendix E Guidelines to Rule 35, Bear Valley has unique local conditions that require it, in certain circumstances, to go beyond the regulated minimum vegetation clearance standards of GO 95. The need to exceed some of the minimum standards is based primarily on the Bear Valley service area's specific climate characteristics, including the high likelihood of icing conditions. In addition, tree limbs and branches are subject to weakening due to repeated high winds, snow, and ice weight. As tree limbs and branches weaken over time due to these wintry conditions repeatedly over the years, they are ultimately very susceptible to breaking away during high and gusty wind events of any kind, including during dry Santa Ana winds during the fire season. These events are the greatest cause for concern as they increase the probability of ignitions occurring during conditions that would support spread of a wildfire. Most of Bear Valley's service area is heavily wooded and has significant brush growth. Climate change predictions indicate drought, dryness, and elevated temperatures will continue on their increasing trends. Therefore, Bear Valley has established the following clearance specifications:

- **Radial Clearances:** Vegetation that is within the minimum 72-inch safe clearance distance will be trimmed to at least 12 feet in accordance with Appendix E Guidelines to Rule 35 of GO 95. Considering vegetation species and growth rates and characteristics, BVES's contractor will even trim beyond 12 feet if necessary to help to ensure that the vegetation remains outside the minimum 72-inch safe clearance distance for the entire length of the vegetation management program cycle (3-years). Vegetation that is outside the minimum 72-inch safe clearance distance, but is expected, to encroach the 72-inch safe clearance distance prior to the next scheduled preventative vegetation management visit (normally 3 years), taking into account vegetation species and growth rates and characteristics, will be trimmed to at least 12 feet in accordance with Appendix E Guidelines to Rule 35 of GO 95. In so far as possible, trimming shall be designed to achieve the appropriate clearance from the power lines without damaging the structural integrity or health of the tree(s).
- **Drip Line:** All vegetation within the drip line of primary conductors that has the potential of growing into the secondary system or within 12 feet of the energized primary conductors within the 3-year vegetation management program cycle will be removed.

9.2.1.4 Fall-in Mitigation

Bear Valley has a fall-in mitigation plan that proactively removes or remediates trees that are dead or rotten, as well as diseased portions of otherwise healthy trees which overhang or lean toward and may fall into a span of power lines. Note that this may apply to trees outside the clearance zone (for example, a dead tree across the street may pose a danger to BVES power lines). BVES will also consider the removal of any fast-growing trees, such as Poplars, Aspens, or Cottonwood, rotten or diseased trees, and healthy trees hanging over or leaning towards bare lines. All such trees will be trimmed to 12 feet minimum and evaluated for removal in each case. This information will be tracked in BVES's tree tracking program.

BVES uses all of the VM inspection programs to determine where dead, diseased, or dying trees are located. Once a tree is identified as a possible risk, the utility forester, an International Society of Arboriculture (ISA) certified arborist, conducts an ISA Level 2 Tree Risk Assessment. Once the assessment is completed, the tree is assigned level of risk. Level 1 is considered to be an immediate threat of failure with a requirement to be resolved within 24 hours. Level 2 discrepancies are of an urgent nature but do not rise to the Level 1 classification. Level 2 discrepancies need to be addressed and remediated within 30-days. Level 3 discrepancies are non-urgent and will carry a resolution timeframe of 1 year.

9.2.1.5 Scheduling

Bear Valley conducts detailed inspections using a mix of schedule and risk prioritization in determining which circuits are to be inspected. GO 165 provides specific minimum inspection schedule criteria, which Bear Valley follows. For overhead systems, Bear Valley is required to inspect these systems every five years. Bear Valley inspects unhardened (bare conductor systems) at least every three years on a risk prioritization basis and hardened covered conductor systems every five years. All of Bear Valley's unhardened bare conductor circuits are located in the HFTD Tier 2. All detailed inspections are conducted in compliance with GO 165 and GO 95 (Rule 18). BVES divides its system up and conducts detailed inspections on every circuit.

It should be noted that 100% of Bear Valley's system is inspected via the following annual inspections:

- Patrol Inspections (VM_2)
- UAV HD Photography/Videography Inspections (VM_3)
- LiDAR (VM_4)
- 3rd Party Ground Patrol Inspections (VM_5)
- Satellite Inspection (VM_7)

9.2.1.6 Updates

Bear Valley is including risk prioritized scheduling for detailed inspections. Bear Valley has not made any other additional changes since the last WMP submission. Currently, Bear Valley does not have any further planned updates to this initiative. There were no lessons learned in this area.

9.2.2 Patrol inspections (Tracking ID: VM_2)

9.2.2.1 Overview and Area Inspected

Bear Valley's Field Inspector conducts a patrol inspection of the entire overhead system per GO 165 once per year. Bear Valley also contracts out a second patrol inspection of its entire system in its 3rd Party Ground Patrol Inspection (GD_5), which is discussed in Section 9.2.5. This expands upon what is required by GO 165 requirements.

9.2.2.2 Procedures

Patrol inspections are intended to identify obvious problems or hazards while performing a "drive-by" patrol. The problems sought are those which are readily observable when performing a driving-, foot-, or aerial-patrol and do not require the patrolman to enter properties unless facilities cannot be observed from public access locations.

The Wildfire Mitigation and Reliability Engineer reviews the results of patrol inspections and assigns corrective action to the vegetation clearance crews. Additionally, the Wildfire Mitigation and Reliability Engineer reviews the results of patrol inspections as well as other vegetation inspections to determine if there are systemic issues that must be addressed. Finally, the results of patrol inspections are cross checked against other vegetation inspections to evaluate the quality and effectiveness of each inspection type.

9.2.2.3 Clearance

GO 95, Rules for Overhead Electric Line Construction, Rule 35 identifies the minimum radial clearances for vegetation around power lines. In accordance with GO 95 Appendix E Guidelines to Rule 35, Bear Valley has unique local conditions that require it, in certain circumstances, to go beyond the regulated minimum vegetation clearance standards of GO 95. The need to exceed some of the minimum standards is based primarily on Bear Valley service area's specific climate characteristics, including the high likelihood of icing conditions. In addition, tree limbs and branches are subject to weakening due to repeated high winds, snow, and ice weight. As tree limbs and branches weaken over time due to these wintry conditions repeatedly over the years, they are ultimately very susceptible to breaking away during high and gusty wind events of any kind, including during dry Santa Ana winds during the fire season. These events are the greatest cause for concern as they increase the probability of ignitions occurring during conditions that would support spread of a wildfire. Most of Bear Valley's service area is heavily wooded and has significant brush growth. Climate change predictions indicate drought, dryness, and elevated temperatures will continue on their increasing trends. Therefore, Bear Valley has established the following clearance specifications:

- **Radial Clearances:** Vegetation that is within the minimum 72-inch safe clearance distance will be trimmed to at least 12 feet in accordance with Appendix E Guidelines to Rule 35 of GO 95. Considering vegetation species and growth rates and characteristics, BVES's contractor will even trim beyond 12 feet if necessary to help to ensure that the vegetation remains outside the minimum 72-inch safe clearance distance for the entire length of the vegetation management program cycle (3-years). Vegetation that is outside the minimum 72-inch safe clearance distance, but is expected to encroach the 72-inch safe clearance distance prior to the next scheduled preventative vegetation management visit (normally 3 years), taking into account vegetation species and growth rates and characteristics, will be trimmed to at least 12 feet in accordance with Appendix E Guidelines to Rule 35 of GO 95. In so far as possible, trimming shall be designed to achieve the appropriate clearance from the power lines without damaging the structural integrity or health of the tree(s).

- **Drip Line:** All vegetation within the drip line of primary conductors that has the potential of growing into the secondary system or within 12 feet of the energized primary conductors within the 3-year vegetation management program cycle will be removed.

9.2.2.4 Fall-in Mitigation

Bear Valley has a fall-in mitigation plan that proactively removes or remediates trees that are dead or rotten, as well as diseased portions of otherwise healthy trees which overhang or lean toward and may fall into a span of power lines. Note that this may apply to trees outside the clearance zone (for example, a dead tree across the street may pose a danger to BVES power lines). BVES will also consider the removal of any fast-growing trees, such as Poplars, Aspens, or Cottonwood, rotten or diseased trees, and healthy trees hanging over or leaning towards bare lines. All such trees will be trimmed to 12 feet minimum and evaluated for removal in each case. This information will be tracked in BVES's tree tracking program.

BVES uses all of the VM inspection programs to determine where dead, diseased, or dying trees are located. Once a tree is identified as a possible risk, the utility forester, an International Society of Arboriculture (ISA) certified arborist, conducts an ISA Level 2 Tree Risk Assessment. Once the assessment is completed, the tree is assigned a level of risk. Level 1 is considered to be an immediate threat of failure with a requirement to be resolved within 24 hours. Level 2 discrepancies are of an urgent nature but do not rise to the Level 1 classification. Level 2 discrepancies need to be addressed and remediated within 30-days. Level 3 discrepancies are non-urgent and will carry a resolution timeframe of 1 year.

9.2.2.5 Scheduling

Patrol inspections are conducted annually in compliance with GO 165. The inspections cover the entirety of Bear Valley's overhead facilities. Because all of Bear Valley's service area is in HFTD Tier 2 or Tier 3 and the entire system is inspected each year, risk prioritization is limited to the sequencing of inspecting circuits. Higher ignition risk circuits (unhardened bare conductor) are inspected prior to the fire season.

Patrol inspections are also conducted after any outage to ensure that there are no possible vegetation issues on the circuit experiencing a fault.

9.2.2.6 Updates

Bear Valley has prioritized inspections in areas that have a higher risk and sections of lines that have not been hardened (converted from bare conductors to covered conductors). Bear Valley has not made any other changes since the last WMP submission. Currently, Bear Valley does not have any further planned updates to this initiative. There were no lessons learned in this area.

9.2.3 UAV Photography/Videography (Tracking ID: VM_3)

9.2.3.1 Overview and Area Inspected

Bear Valley conducts an annual UAV HD Photography/Videography inspection on its entire overhead system. This inspection uses UAVs to take high-definition photography and video of all overhead facilities looking for possible vegetation encroachments. Bear Valley started conducting UAV photography/videography inspections in 2021 and has completed 4 annual inspections.

9.2.3.2 Procedures

Bear Valley conducts an annual UAV HD Photography/Videography inspection. This initiative is a high-definition (HD) imagery aerial survey of Bear Valley's sub-transmission and distribution facilities and power lines inspection of rights-of-way and adjacent vegetation that may be hazardous, which exceeds or otherwise go beyond those mandated by rules and regulations, in terms of frequency, inspection checklist requirements or detail, analysis of and response to problems identified, or other aspects of inspection or records kept. This relatively quick and accurate inspection allows BVES to verify, document and resolve vegetation encroachment issues before they make contact with bare conductors.

The Wildfire Mitigation and Reliability Engineer reviews the results of UAV HD Photography/Videography inspection and assigns corrective action to the vegetation clearance crews. Each finding in the inspection is field checked. Additionally, the Wildfire Mitigation and Reliability Engineer reviews the results of UAV HD Photography/Videography inspections as well as other vegetation inspections to determine if there are systemic issues that must be addressed. Finally, the results of UAV HD Photography/Videography inspections are cross checked against other vegetation inspections to evaluate the quality and effectiveness of each inspection type.

9.2.3.3 Clearance

GO 95, Rules for Overhead Electric Line Construction, Rule 35 identifies the minimum radial clearances for vegetation around power lines. In accordance with GO 95 Appendix E Guidelines to Rule 35, Bear Valley has unique local conditions that require it, in certain circumstances, to go beyond the regulated minimum vegetation clearance standards of GO 95. The need to exceed some of the minimum standards is based primarily on the Bear Valley service area's specific climate characteristics, including the high likelihood of icing conditions. In addition, tree limbs and branches are subject to weakening due to repeated high winds, snow, and ice weight. As tree limbs and branches weaken over time due to these wintry conditions repeatedly over the years, they are ultimately very susceptible to breaking away during high and gusty wind events of any kind, including during dry Santa Ana winds during the fire season. These events are the greatest cause for concern as they increase the probability of ignitions occurring during conditions that would support spread of a wildfire. Most of Bear Valley's service area is heavily wooded and has significant brush growth. Climate change predictions indicate drought, dryness, and elevated temperatures will continue on their increasing trends. Therefore, Bear Valley has established the following clearance specifications:

- **Radial Clearances:** Vegetation that is within the minimum 72-inch safe clearance distance will be trimmed to at least 12 feet in accordance with Appendix E Guidelines to Rule 35 of GO 95. Considering vegetation species and growth rates and characteristics, BVES's contractor will even trim beyond 12 feet if necessary to help to ensure that the vegetation remains outside the minimum 72-inch safe clearance distance for the entire length of the vegetation management program cycle (3-years). Vegetation that is outside the minimum 72-inch safe clearance distance, but is expected, to encroach the 72-inch safe clearance distance prior to the next scheduled preventative vegetation management visit (normally 3 years), taking into account vegetation species and growth rates and characteristics, will be trimmed to at least 12 feet in accordance with Appendix E Guidelines to Rule 35 of GO 95. In so far as possible, trimming shall be designed to achieve the appropriate clearance from the power lines without damaging the structural integrity or health of the tree(s).
- **Drip Line:** All vegetation within the drip line of primary conductors that has the potential of growing into the secondary system or within 12 feet of the energized primary conductors within the 3-year vegetation management program cycle will be removed.

9.2.3.4 Fall-in Mitigation

Bear Valley has a fall-in mitigation plan that proactively removes or remediates trees that are dead or rotten, as well as diseased portions of otherwise healthy trees which overhang or lean toward and may fall into a span of power lines. Note that this may apply to trees outside the clearance zone (for example, a dead tree across the street may pose a danger to BVES power lines). BVES will also consider the removal of any fast-growing trees, such as Poplars, Aspens, or Cottonwood, rotten or diseased trees, and healthy trees hanging over or leaning towards bare lines. All such trees will be trimmed to 12 feet minimum and evaluated for removal in each case. This information will be tracked in BVES's tree tracking program.

BVES uses all of the VM inspection programs to determine where dead, deseased, or dying trees are located. Once a tree is identified as a possible risk, the utility forester, an International Society of Arboriculture (ISA) certified arborist, conducts an ISA Level 2 Tree Risk Assessment. Once the assessment is completed, the tree is assigned level of risk. Level 1 is considered to be an immediate threat of failure with a requirement to be resolved within 24 hours. Level 2 discrepancies are of an urgent nature but do not rise to the Level 1 classification. Level 2 discrepancies need to be addressed and remediated within 30-days. Level 3 discrepancies are non-urgent and will carry a resolution timeframe of 1 year.

9.2.3.5 Scheduling

Bear Valley conducts an annual UAV HD Photography/Videography inspection on its entire overhead system. BVES strives for the inspection to be completed before the onset of peak fire season. The survey begins as soon as conditions from winter snow improve. The survey typically will begin in areas that are accessible to the survey teams. Inspections typically begin in late spring and finishes in early summer. Processing of the large amount of data can take up to 1-2 months before the contractor delivers the inspection findings. Level 1 findings are reported immediately. BVES has used the UAV HD Photography/Videography off cycle to evaluate damages after storms in areas that are difficult to access.

UAV HD Photography/videography inspections are conducted annually and cover the entirety of Bear Valley's overhead facilities. All of Bear Valley's service territory is in HFTD Tier 2 or Tier 3 and is very compact and the UAV HD Photography/videography inspection data collection is done over a short period of time, therefore risk prioritization scheduling is not used in assigning these inspections.

9.2.3.6 Updates

BVES has not made changes since the last WMP submission. Currently, Bear Valley does not have any planned updates to this initiative. There were no lessons learned in this area.

9.2.4 LiDAR Inspection (Tracking ID: VM_4)

9.2.4.1 Overview and Area Inspected

Bear Valley performs vegetation clearance inspections utilizing Light Detection and Ranging (LiDAR) sensors to provide an accurate and objective analysis of vegetation clearances from the power lines. The inspection uses a combination of UAV and truck mounted equipment to assess vegetation clearances. This equipment is able to very accurately identify encroachments near power lines using LiDAR technology. Bear Valley conducts annual LiDAR inspection on its entire overhead system. The inspection in 2024 was Bear Valley's 6th annual inspection. Bear Valley will continue to perform this inspection throughout this WMP cycle.

9.2.4.2 Procedures

Bear Valley conducts one LiDAR sweep per year to evaluate the effectiveness of clearance efforts and identify potential wildfire hazards. This is an accurate inspection using LiDAR (Light Detection and Ranging) inspection, which uses a system of lasers and software to develop surveys of the overhead sub-transmission and distribution systems, to accurately determine vegetation clearances to conductors. Bear Valley began using LiDAR through a pilot project initiative using both helicopter and fixed wing flights, as well as via a truck-mounted mobile system. Given the proximity of the majority of Bear Valley's electrical system to the roadways and the tree canopy that is typical of distribution systems, truck-mounted mobile LiDAR is combined with aircraft LiDAR to render the inspection more effective.

LiDAR survey findings are rated in accordance with GO 95 Rule 18 (level 1, 2, or 3) and entered into the distribution inspection GIS database. Level 1 findings are reported immediately to the Field Operations Supervisor who will direct corrective action as soon as possible to resolve the issue or reduce its severity to Level 2 so that more time is available to perform permanent corrective action. When BVES receives the LiDAR survey report, each finding is investigated by qualified personnel in evaluating vegetation clearances around power lines to validate the actual conditions and reassign the priority per GO 95, if deemed appropriate. The LiDAR contractor will immediately inform BVES of any level 1 findings so they may be corrected or resolved to a level 2 or 3 finding as soon as possible.

The Wildfire Mitigation and Reliability Engineer reviews the results of LiDAR surveys and assigns corrective action to the vegetation clearance crews. Additionally, the Wildfire Mitigation and Reliability Engineer reviews the result of LiDAR surveys as well as other vegetation inspections to determine if there are systemic issues that must be addressed. Finally, the results of LiDAR surveys are validated against other vegetation inspections to evaluate the quality and effectiveness of each inspection type. Frequency or trigger

BVES performs a LiDAR survey of all circuits each year. It takes its expert contractor approximately two weeks to gather LiDAR data on the entire BVES system.

9.2.4.3 Clearance

GO 95, Rules for Overhead Electric Line Construction, Rule 35 identifies the minimum radial clearances for vegetation around power lines. In accordance with GO 95 Appendix E Guidelines to Rule 35, Bear Valley's has unique local conditions that require it, in certain circumstances, to go beyond the regulated minimum vegetation clearance standards of GO 95. The need to exceed some of the minimum standards is based primarily on the Bear Valley service area's specific climate characteristics, including the high likelihood of icing conditions. In addition, tree limbs and branches are subject to weakening due to repeated high winds, snow, and ice weight. As tree limbs and branches weaken over time due to these wintry conditions repeatedly over the years, they are ultimately very susceptible to breaking away during high and gusty wind events of any kind, including during dry Santa Ana winds during the fire season. These events are the greatest cause for concern as they increase the probability of ignitions occurring during conditions that would support spread of a wildfire. Most of Bear Valley's service area is heavily wooded and has significant brush growth. Climate change predictions indicate drought, dryness, and elevated temperatures will continue on their increasing trends. Therefore, Bear Valley has established the following clearance specifications:

- **Radial Clearances:** Vegetation that is within the minimum 72-inch safe clearance distance will be trimmed to at least 12 feet in accordance with Appendix E Guidelines to Rule 35 of GO 95. Considering vegetation species and growth rates and characteristics, BVES's contractor will even trim beyond 12 feet if necessary to help to ensure that the vegetation remains outside the minimum 72-inch safe clearance distance for the entire length of the vegetation management program cycle (3-years). Vegetation that is outside the minimum 72-inch safe clearance distance, but is expected, to encroach the 72-inch safe clearance distance prior to the next scheduled preventative vegetation management visit (normally 3 years), taking into account vegetation species and growth rates and characteristics, will be trimmed to at least 12 feet in accordance with Appendix E Guidelines to Rule 35 of GO 95. In so far as possible, trimming shall be designed to achieve the appropriate clearance from the power lines without damaging the structural integrity or health of the tree(s).
- **Drip Line:** All vegetation within the drip line of primary conductors that has the potential of growing into the secondary system or within 12 feet of the energized primary conductors within the 3-year vegetation management program cycle will be removed.

9.2.4.4 Fall-in Mitigation

Bear Valley has a fall-in mitigation plan that proactively removes or remediates trees that are dead or rotten, as well as diseased portions of otherwise healthy trees which overhang or lean toward and may fall into a span of power lines. Note that this may apply to trees outside the clearance zone (for example, a dead tree across the street may pose a danger to BVES power lines). BVES will also consider the removal of any fast-growing trees, such as Poplars, Aspens, or Cottonwood, rotten or diseased trees, and healthy trees hanging over or leaning towards bare lines. All such trees will be trimmed to 12 feet minimum and evaluated for removal in each case. This information will be tracked in BVES's tree tracking program.

BVES uses all of the VM inspection programs to determine where dead, diseased, or dying trees are located. Once a tree is identified as a possible risk, the utility forester, an International Society of Arboriculture (ISA) certified arborist, conducts an ISA Level 2 Tree Risk Assessment. Once the assessment is completed, the tree is assigned a level of risk. Level 1 is considered to be an immediate threat of failure with a requirement to be resolved within 24 hours. Level 2 discrepancies are of an urgent nature but do not rise to the Level 1 classification. Level 2 discrepancies need to be addressed and remediated within 30-days. Level 3 discrepancies are non-urgent and will carry a resolution timeframe of 1 year.

9.2.4.5 Scheduling

LiDAR inspections use a combination of UAV and truck mounted LiDAR sensors. BVES conducts LiDAR inspection on its entire overhead system each year. BVES strives for the survey to be completed before the onset of peak fire season. The survey begins as soon as conditions from winter snow improve. The survey typically will begin in areas that are accessible to the survey teams. The entire inspection collection takes about 2-3 weeks. Once the inspection collection is completed the contractor takes 1-2 months to complete the analysis and for BVES to receive the deliverables.

BVES does not prioritize high risk areas because the entire service area is completed in a relatively short amount of time. Additionally, all of the findings are received at the same time. Therefore, using risk prioritization would not increase the delivery date for higher risk areas. All of Bear Valley's service area is in the HFTD.

9.2.4.6 Updates

BVES has not made changes since the last WMP submission. Currently, Bear Valley does not have any planned updates to this initiative. There were no lessons learned in this area.

9.2.5 3rd Party Ground Patrol (Tracking ID: VM_5)

9.2.5.1 Overview and Area Inspected

The 3rd party ground patrol is an inspection that is conducted in accordance with GO 165 and GO 95. This is an additional patrol inspection that is conducted by a contracted inspector on the entire overhead system each year. Since 2019, Bear Valley has conducted 6 annual 3rd party ground patrol inspections of its entire overhead system.

9.2.5.2 Procedures

Bear Valley conducts an annual 3rd Party Ground Patrol Inspection. This inspection is conducted by a contracted 3rd party and satisfies GO 165 patrol inspection requirements and is in effect an additional annual GO 165 patrol inspection. BVES contracts experienced and qualified electrical distribution vegetation inspection contractors to perform this ground patrol inspection. The 3rd Party Ground Patrol Inspection is a careful, visual inspection of overhead electric distribution lines and equipment along rights-of-way that is designed to identify obvious hazards. This includes careful examination of individual pieces of equipment and structures to determine the condition of each rated and recorded component and vegetation clearances to bare conductor and other components.

3rd Party Ground Patrol Inspection findings are rated in accordance with G.O. 95 Rule 18 (Level 1, 2, or 3) and entered into the distribution inspection GIS database. Level 1 findings are reported immediately to the Field Operations Supervisor who will direct corrective action as soon as possible to resolve the issue or reduce its severity to Level 2 so that more time is available to perform permanent corrective action.

The Wildfire Mitigation and Reliability Engineer reviews the results of the 3rd Party Ground Patrol Inspections and assigns corrective action to the vegetation clearance crews. Additionally, the Wildfire Mitigation and Reliability Engineer reviews the results of the 3rd Party Ground Patrol Inspections, as well as other vegetation inspections, to determine if there are systemic issues that must be addressed. Finally, the results of the 3rd Party Ground Patrol Inspections are validated against other vegetation inspections to evaluate the quality and effectiveness of each inspection type.

9.2.5.3 Clearance

GO 95, Rules for Overhead Electric Line Construction, Rule 35 identifies the minimum radial clearances for vegetation around power lines. In accordance with GO 95 Appendix E Guidelines to Rule 35, Bear Valley has unique local conditions that require it, in certain circumstances, to go beyond the regulated minimum vegetation clearance standards of GO 95. The need to exceed some of the minimum standards is based primarily on the Bear Valley service area's specific climate characteristics, including the high likelihood of icing conditions. In addition, tree limbs and branches are subject to weakening due to repeated high winds, snow, and ice weight. As tree limbs and branches weaken over time due to these wintry conditions repeatedly over the years, they are ultimately very susceptible to breaking away during high and gusty wind events of any kind, including during dry Santa Ana winds during the fire season. These events are the greatest cause for concern as they increase the probability of ignitions occurring during conditions that would support spread of a wildfire. Most of Bear Valley's service area is heavily wooded and has significant brush growth. Climate change predictions indicate drought, dryness, and elevated temperatures will continue on their increasing trends. Therefore, Bear Valley has established the following clearance specifications:

- **Radial Clearances:** Vegetation that is within the minimum 72-inch safe clearance distance will be trimmed to at least 12 feet in accordance with Appendix E Guidelines to Rule 35 of GO 95. Considering vegetation species and growth rates and characteristics, BVES's contractor will even trim beyond 12 feet if necessary to help to ensure that the vegetation remains outside the minimum 72-inch safe clearance distance for the entire length of the vegetation management program cycle (3-years). Vegetation that is outside the minimum 72-inch safe clearance distance, but is expected to encroach the 72-inch safe clearance distance prior to the next scheduled preventative vegetation management visit (normally 3 years), taking into account vegetation species and growth rates and characteristics, will be trimmed to at least 12 feet in accordance with Appendix E Guidelines to Rule 35 of GO 95. In so far as possible, trimming shall be designed to achieve the appropriate clearance from the power lines without damaging the structural integrity or health of the tree(s).

- **Drip Line:** All vegetation within the drip line of primary conductors that has the potential of growing into the secondary system or within 12 feet of the energized primary conductors within the 3-year vegetation management program cycle will be removed.

9.2.5.4 Fall-in Mitigation

Bear Valley has a fall-in mitigation plan that proactively removes or remediates trees that are dead or rotten, as well as diseased portions of otherwise healthy trees which overhang or lean toward and may fall into a span of power lines. Note that this may apply to trees outside the clearance zone (for example, a dead tree across the street may pose a danger to BVES power lines). BVES will also consider the removal of any fast-growing trees, such as Poplars, Aspens, or Cottonwood, rotten or diseased trees, and healthy trees hanging over or leaning towards bare lines. All such trees will be trimmed to 12 feet minimum and evaluated for removal in each case. This information will be tracked in BVES's tree tracking program.

BVES uses all of the VM inspection programs to determine where dead, diseased, or dying trees are located. Once a tree is identified as a possible risk, the utility forester, an International Society of Arboriculture (ISA) certified arborist, conducts an ISA Level 2 Tree Risk Assessment. Once the assessment is completed, the tree is assigned a level of risk. Level 1 is considered to be an immediate threat of failure with a requirement to be resolved within 24 hours. Level 2 discrepancies are of an urgent nature but do not rise to the Level 1 classification. Level 2 discrepancies need to be addressed and remediated within 30-days. Level 3 discrepancies are non-urgent and will carry a resolution timeframe of 1 year.

9.2.5.5 Scheduling

The 3rd party ground patrol is conducted on the entire overhead system each year. The inspection occurs in Q3 and takes less than one month to complete. The findings are provided to BVES within one week of the completed inspections.

BVES provides a list of circuits to the contractor that prioritize areas that contain bare conductors to be inspected before inspecting circuits that are hardened with covered conductor.

9.2.5.6 Updates

BVES has not made changes since the last WMP submission. Currently, BVES evaluation demonstrates that there is no need to update the initiative. There were no lessons learned in this area.

9.2.6 Substation Inspection (Tracking ID: VM_6)

9.2.6.1 Overview and Area Inspected

Substation inspections are conducted on each in-service BVES substation every month. This inspection is intended to identify any vegetation growth within or near a substation that may be encroaching onto any equipment or has the potential to encroach. Additionally, BVES maintains defensible space around its substations.

9.2.6.2 Procedures

Monthly inspections of the BVES substations are conducted in compliance with the GO 174 recommendations. The inspection includes a detailed visual examination and written record of all components pertaining to the 34kV/4kV substations, as well as if vegetation growth and encroachment has occurred. Inspection results are reviewed by the Wildfire Mitigation and Reliability Engineer and corrective action is assigned to a vegetation contractor. The vegetation contractor coordinates any clearance activities with the substation technician to provide safety escorts. The Wildfire Mitigation and Reliability Engineer also looks for trends and anomalies.

9.2.6.3 Clearance

Bear Valley requires substations be free of weed, grass, and brush growth. Additionally, Bear Valley maintains defensible space around its substations.

GO 95, Rules for Overhead Electric Line Construction, Rule 35 identifies the minimum radial clearances for vegetation around power lines. In accordance with GO 95 Appendix E Guidelines to Rule 35, Bear Valley has unique local conditions that require it, in certain circumstances, to go beyond the regulated minimum vegetation clearance standards of GO 95. The need to exceed some of the minimum standards is based primarily on Bear Valley service area's specific climate characteristics, including the high likelihood of icing conditions. In addition, tree limbs and branches are subject to weakening due to repeated high winds, snow, and ice weight. As tree limbs and branches weaken over time due to these wintry conditions repeatedly over the years, they are ultimately very susceptible to breaking away during high and gusty wind events of any kind, including during dry Santa Ana winds during the fire season. These events are the greatest cause for concern as they increase the probability of ignitions occurring during conditions that would support spread of a wildfire. Most of Bear Valley's service area is heavily wooded and has significant brush growth. Climate change predictions indicate drought, dryness, and elevated temperatures will continue on their increasing trends. Therefore, Bear Valley has established the following clearance specifications:

- **Radial Clearances:** Vegetation that is within the minimum 72-inch safe clearance distance will be trimmed to at least 12 feet in accordance with Appendix E Guidelines to Rule 35 of GO 95. Considering vegetation species and growth rates and characteristics, BVES's contractor will even trim beyond 12 feet if necessary to help to ensure that the vegetation remains outside the minimum

72-inch safe clearance distance for the entire length of the vegetation management program cycle (3-years). Vegetation that is outside the minimum 72-inch safe clearance distance, but is expected to encroach the 72-inch safe clearance distance prior to the next scheduled preventative vegetation management visit (normally 3 years), taking into account vegetation species and growth rates and characteristics, will be trimmed to at least 12 feet in accordance with Appendix E Guidelines to Rule 35 of GO 95. In so far as possible, trimming shall be designed to achieve the appropriate clearance from the power lines without damaging the structural integrity or health of the tree(s).

- **Drip Line:** All vegetation within the drip line of primary conductors that has the potential of growing into the secondary system or within 12 feet of the energized primary conductors within the 3-year vegetation management program cycle will be removed.

9.2.6.4 Fall-in Mitigation

Bear Valley has a fall-in mitigation plan that proactively removes or remediates trees that are dead or rotten, as well as diseased portions of otherwise healthy trees which overhang or lean toward and may fall into a span of power lines. Note that this may apply to trees outside the clearance zone (for example, a dead tree across the street may pose a danger to BVES power lines). BVES will also consider the removal of any fast-growing trees, such as Poplars, Aspens, or Cottonwood, rotten or diseased trees, and healthy trees hanging over or leaning towards bare lines. All such trees will be trimmed to 12 feet minimum and evaluated for removal in each case. This information will be tracked in BVES's tree tracking program.

BVES uses all of the VM inspection programs to determine where dead, diseased, or dying trees are located. Once a tree is identified as a possible risk, the utility forester, an International Society of Arboriculture (ISA) certified arborist, conducts an ISA Level 2 Tree Risk Assessment. Once the assessment is completed, the tree is assigned a level of risk. Level 1 is considered to be an immediate threat of failure with a requirement to be resolved within 24 hours. Level 2 discrepancies are of an urgent nature but do not rise to the Level 1 classification. Level 2 discrepancies need to be addressed and remediated within 30-days. Level 3 discrepancies are non-urgent and will carry a resolution timeframe of 1 year.

9.2.6.5 Scheduling

Substation inspections are conducted on each in-service BVES substation every month per GO-174.

BVES does not prioritize substation based on risk because the inspection of all substations is typically conducted on the same day. This makes prioritization less useful for this inspection process.

9.2.6.6 Updates

BVES has not made changes since the last WMP submission. Currently, Bear Valley does not have any planned updates to this initiative. There were no lessons learned in this area.

9.2.7 Satellite imaging inspection (Tracking ID: VM_7)

9.2.7.1 Overview and Area Inspected

BVES has a contracted company that completes one satellite imaging scan per year of the entire service territory. This inspection is meant to identify dying trees, grow-in risks, and possible encroachments.

9.2.7.2 Procedures

BVES is using a contractor to provide a complementary review of its vegetation management around electrical lines and equipment.

AiDash software uses satellite imaging to provide a rapid assessment of BVES's service territory and insight into whether vegetation should be assessed or moved up in priority for upcoming patrol, detailed, or third-party ground inspections. The AiDash assessment allows BVES to gain a comprehensive understanding of its service territory at a glance. AiDash also provides a complementary review of BVES's vegetation management program. BVES acknowledged the trend in wildfire mitigation towards validation and confirmation of planning associated with Vegetation and Asset based work. AiDash allows BVES to confirm that its planning efforts for vegetation management are not based upon merely institutional knowledge, but rather validated by objective satellite imagery and AI-based future state modeling and projections. This provides insight into vegetation that should be assessed or moved up in priority for upcoming patrol, detailed, or third-party ground inspections. This imagery also provides data on tree mortality, grow-ins, and encroachments to BVES equipment. This assessment will allow BVES to understand the complete state of its service territory at a glance.

9.2.7.3 Clearance

GO 95, Rules for Overhead Electric Line Construction, Rule 35 identifies the minimum radial clearances for vegetation around power lines. In accordance with GO 95 Appendix E Guidelines to Rule 35, Bear Valley has unique local conditions that require it, in certain circumstances, to go beyond the regulated minimum vegetation clearance standards of GO 95. The need to exceed some of the minimum standards is based primarily on the Bear Valley service area's specific climate characteristics, including the high likelihood of icing conditions. In addition, tree limbs and branches are subject to weakening due to repeated high winds, snow, and ice weight. As tree limbs and branches weaken over time due to these wintry conditions repeatedly over the years, they are ultimately very susceptible to breaking away during high and gusty wind events of any kind, including during dry Santa Ana winds during the fire season. These events are the greatest cause for concern as they increase the probability of ignitions occurring during conditions that would support spread of a wildfire. Most of Bear Valley's service area is heavily wooded and has significant brush growth. Climate change predictions indicate drought, dryness, and elevated temperatures will continue on their increasing trends. Therefore, Bear Valley has established the following clearance specifications:

- **Radial Clearances:** Vegetation that is within the minimum 72-inch safe clearance distance will be trimmed to at least 12 feet in accordance with Appendix E Guidelines to Rule 35 of GO 95. Considering vegetation species and growth rates and characteristics, BVES's contractor will even trim beyond 12 feet if necessary to help to ensure that the vegetation remains outside the minimum 72-inch safe clearance distance for the entire length of the vegetation management program cycle (3-years). Vegetation that is outside the minimum 72-inch safe clearance distance, but is expected to encroach the 72-inch safe clearance distance prior to the next scheduled preventative vegetation management visit (normally 3 years), taking into account vegetation species and growth rates and characteristics, will be trimmed to at least 12 feet in accordance with Appendix E Guidelines to Rule 35 of GO 95. In so far as possible, trimming shall be designed to achieve the appropriate clearance from the power lines without damaging the structural integrity or health of the tree(s).
- **Drip Line:** All vegetation within the drip line of primary conductors that has the potential of growing into the secondary system or within 12 feet of the energized primary conductors within the 3-year vegetation management program cycle will be removed.

9.2.7.4 Fall-in Mitigation

Bear Valley has a fall-in mitigation plan that proactively removes or remediates trees that are dead or rotten, as well as diseased portions of otherwise healthy trees which overhang or lean toward and may fall into a span of power lines. Note that this may apply to trees outside the clearance zone (for example, a dead tree across the street may pose a danger to BVES power lines). BVES will also consider the removal of any fast-growing trees, such as Poplars, Aspens, or Cottonwood, rotten or diseased trees, and healthy trees hanging over or leaning towards bare lines. All such trees will be trimmed to 12 feet minimum and evaluated for removal in each case. This information will be tracked in BVES's tree tracking program.

BVES uses all of the VM inspection programs to determine where dead, diseased, or dying trees are located. Once a tree is identified as a possible risk, the utility forester, an International Society of Arboriculture (ISA) certified arborist, conducts an ISA Level 2 Tree Risk Assessment. Once the assessment is completed, the tree is assigned a level of risk. Level 1 is considered to be an immediate threat of failure with a requirement to be resolved within 24 hours. Level 2 discrepancies are of an urgent nature but do not rise to the Level 1 classification. Level 2 discrepancies need to be addressed and remediated within 30-days. Level 3 discrepancies are non-urgent and will carry a resolution timeframe of 1 year.

9.2.7.5 Scheduling

Bear Valley contracted a company that completes one satellite imaging scan per year of the entire service territory. This inspection is meant to identify dying trees, grow-in risks, and possible encroachments. Data acquisition for the inspection is relatively short (1 day). Processing the data and providing the inspection results takes the contractor about a month.

BVES conducts this satellite inspection when all of the deciduous tree regain their leaves but before the peak of fire season in order to get a quick vegetation assessment. This allows BVES to re-prioritize vegetation clearance work, if necessary, prior to the fire season.

BVES does not prioritize high risk areas because the entire service territory is completed in a relatively short amount of time. Additionally, all of the findings are received at the same time. Therefore, using risk prioritization would not increase the delivery date for higher risk areas. All of Bear Valley's service area is in the HFTD.

9.2.7.6 Updates

Satellite imaging inspection is a new inspection for Bear Valley. There are currently no planned updates to this program. There were no lessons learned in this area.

9.3 Pruning and Removal

9.3.1 Overview

Bear Valley has two initiatives dedicated to pruning and removal. They are:

- Fall-in Mitigation and High-risk Species (VM_8)
- Clearance (VM_9)

Bear Valley has implemented a pruning and removal program that is currently on a 3-year cycle. Bear Valley's target is to prune a minimum of 72 circuit miles per year for clearance and to remove or remediate a minimum of 88 hazard trees per year for fall-in mitigation. This vegetation work schedule allows Bear Valley to maintain its clearances around its power lines.

9.3.2 Procedures

BVES has a vegetation management plan in place that meets or exceeds the minimum requirements of the CPUC's applicable GOs in accordance with best practices. Mowbray's Tree Service Inc., a third-party contractor, executes the vegetation clearing efforts under the direction of BVES. The contractor's work is subject to BVES QA and QC checks. The goal of this plan is to proactively maintain vegetation, so it does not contact electrical infrastructure, thereby preventing wildfires. The utility created the vegetation management plan with wildfire prevention in mind, collaborating with the City of Big Bear Lake, local Fire Departments, and the US Forest Service. The plan will be reviewed and updated on an as needed basis not to exceed three years, depending on changing conditions. The program includes three components: preventative vegetation management, corrective vegetation clearance, and emergency vegetation clearance. Each of these components needs to adhere to particular specifications, detailed below.

- *Preventative Vegetation Management:* This scope of work encompasses ensuring vegetation on BVES overhead sub-transmission and distribution lines adheres to identified clearance specifications.
- *Corrective Vegetation Clearance:* This scope of work consists of completing corrective and emergent vegetation orders to fix clearance discrepancies that the contractor or BVES discovers. If an order is designated as High Priority, the contractor must prioritize that work and make the correction immediately.
- *Emergency Vegetation Clearance Response:* This scope of work requires the vegetation management contractor to support vegetation removal during a major storm event or other disaster. The Contractor must be capable of working extended hours and on weekends and holidays as necessary to clear lines as directed by BVES.

The BVES vegetation management contract also contains provisions to reduce the accumulations of brush and trees waste that may become fuel for wildfires:

- The Contractor is required to remove all wood and wood products and any other wastes generated by the requested service on a daily basis.
- Other requirements related to temporary slash piles, and proper disposal of wood and wood product waste according to applicable laws, rules, and regulations.
- Removal of all dead and rotting trees as well as those with the potential to fall on lines, even if they are outside the required clearance zone.

As mentioned above, all vegetation management work must adhere to certain specifications, as outlined by BVES. GO 95, Rules for Overhead Electric Line Construction, Rule 35 identifies the minimum radial clearances for vegetation around power lines. In accordance with GO 95 Appendix E Guidelines to Rule 35, Bear Valley has unique local conditions that require it, in certain circumstances, to go beyond the regulated minimum vegetation clearance standards of GO 95. The need to exceed some of the minimum standards is based primarily on the Bear Valley service area's specific climate characteristics, including the high likelihood of icing conditions. In addition, tree limbs and branches are subject to weakening due to repeated high winds, snow, and ice weight. As tree limbs and branches weaken over time due to these wintry conditions repeatedly over the years, they are ultimately very susceptible to breaking away during high and gusty wind events of any kind, including during dry Santa Ana winds during the fire season. These events are the greatest cause for concern as they increase the probability of ignitions occurring during conditions that would support spread of a wildfire. Most of Bear Valley's service area is heavily wooded and has significant brush growth. Climate change predictions indicate drought, dryness, and elevated temperatures will continue on their increasing trends. Therefore, Bear Valley has established the following clearance specifications:

Radial Clearances: Vegetation that is within the minimum 72-inch safe clearance distance will be trimmed to at least 12 feet in accordance with Appendix E Guidelines to Rule 35 of GO-95. Considering vegetation species and growth rates and characteristics, BVES's contractor will even trim beyond 12 feet if necessary to help to ensure that the vegetation remains outside the minimum 72-inch safe clearance distance for the entire length of the vegetation management program cycle (3-years).

Vegetation that is outside the minimum 72-inch safe clearance distance, but expected to encroach the 72-inch safe clearance distance prior to the next scheduled preventative vegetation management visit (normally 3 years), taking into account vegetation species and growth rates and characteristics, will be trimmed to at least 12 feet in accordance with Appendix E Guidelines to Rule 35 of GO-95. In so far as possible, trimming shall be designed to achieve the appropriate clearance from the power lines without damaging the structural integrity or health of the tree(s).

Blue Sky Requirement: No vertical coverage shall be allowed above BVES sub-transmission lines (34.5 kV).

Drip Line: All vegetation within the drip line of primary conductors that has the potential of growing into the secondary system or within 12 feet of the energized primary conductors within the 3-year vegetation management program cycle will be removed.

Tree Removal: Trees that are dead, rotten, or diseased, or dead, rotten, or diseased portions of otherwise healthy trees which overhang or lean toward and may fall into a span of power lines, should be removed. Note that this may apply to trees outside the clearance zone (for example, a dead tree across the street may pose a danger to BVES power lines).

Tree Trunk and Major Limb Exception: BVES has developed a flowchart for Field Personnel to use in determining the appropriate action for trees and major limbs in close proximity to bare conductors. If there is a mature tree whose trunk or major limb is within 48 inches of bare conductors, the following action is to be taken:

If the tree or major limb is within 12 inches of the bare conductors regardless of thickness at conductor level, this is a Level 1 discrepancy and shall be immediately remediated by:

- Removing the tree or limb immediately, or

- Installing a tree guard on the line to prevent the tree or limb from contacting the bare conductors and designating the discrepancy as a Level 2 discrepancy to be corrected by removing the tree within 6 months.

If the tree or major limb is less than 6 inches thick at conductor level, then the tree or major limb must be trimmed or removed to achieve 72 inches clearance from bare conductors as follows:

- If there are no burn marks or evidence of the tree or limb contacting bare conductors and the clearance is greater than 48 inches, then this is a Level 2 discrepancy and shall be corrected within 12 months.
- If there are no burn marks or evidence of the tree or limb contacting bare conductors and the clearance is less than 48 inches but greater than 18 inches, then this is a Level 2 discrepancy and shall be corrected within 180 days. A tree guard should be installed as soon as operationally possible.
- If there are burn marks or evidence of the tree or limb contacting bare conductors and/or the clearance is less than 18 inches, then this is a Level 1 discrepancy and shall be immediately remediated by:
  - Removing the tree or limb immediately, or
  - Installing a tree guard on the line to prevent the tree or limb from contacting the bare conductors and designating the discrepancy as a Level 2 discrepancy to be corrected by removing the tree within 6 months.

If the tree or major limb is greater than 6 inches thick at conductor level and greater than 12 inches from bare conductors, then the tree or major limb shall be evaluated to determine if an exemption per GO-95 Rule 35 may be applied and the following actions will be taken:

- If there are burn marks present on the tree or major limb or evidence of the tree or limb contacting the bare conductor, this is a Level 1 discrepancy and shall be immediately remediated by:
  - Removing the tree or major limb immediately, or
  - Installing a tree guard on the line to prevent the tree or limb from contacting the bare conductors and designating the discrepancy as a Level 2 discrepancy to be corrected by removing the tree within 6 months.

- If there are no burn marks present on the tree or major limb and no evidence of the tree or limb contacting the bare conductor, then the tree or major limb may be exempted provided the following:
  - Tree has been established in its current location for at least 10 years.
  - Tree trunk has a diameter at breast height (DBH) of at least 10”.
  - Tree or limb at the conductor level is at least 6” in diameter.
  - Tree is not re-sprouting at conductor level during the time of inspection.
  - Tree is healthy and not otherwise hazardous.

    - Tree is not easily climbable. Note the tree clearance crew can remove branches to render a tree not easily climbable.

- If the tree cannot satisfy one or more of the above criteria, then the tree or major limb must be removed. It should be designated as a Level 2 discrepancy and shall be corrected within 12 months.
- If the tree satisfies all of the above criteria, then the tree may be exempted and remain in place. The tree shall be:
    - Documented on Major Woody Stem Form and approved by the Wildfire Mitigation & Reliability Engineer.
    - Tracked in the Company's GIS applications for vegetation management.
    - Re-evaluated each year.
    - As a precaution, install a tree guard when operationally feasible.

BVES will also consider the removal of any fast-growing trees, such as Poplars, Aspens, or Cottonwood, rotten or diseased trees, and healthy trees hanging over or leaning towards bare lines. All such trees will be trimmed to 12 feet minimum and evaluated for removal in each case. This information is tracked in BVES's tree tracking program.

This vegetation clearance and fall-in mitigation program is accomplished by the forester, pre-inspector, and vegetation management contractor. The pre-inspector inspects the circuit(s) to be cleared prior to dispatching vegetation crews. The pre-inspector documents trees and vegetation that are encroaching onto BVES assets into the AiDASH IVMS database. Once in the database, the contractor's general foreman is able to dispatch crews to the location of work that needs to be mitigated. If a tree is identified as a hazard it will have an assessment completed by the forester and given a risk level to determine the priority of the work. If the pre-inspector identifies a Level 1 violation, crews will be dispatched immediately so that the condition can be mitigated as soon as possible.

9.3.3 Scheduling

All of Bear Valley's assets are in the HFTD Tier 2 and 3; therefore, Bear Valley uses a mix of a set routine schedule and a risk-based prioritization. The schedule for the routine pruning and removal initiatives is on a three-year cycle to ensure the entire service area is visited by vegetation crews and proper clearances are established. The prioritization of higher risk areas are targeted in the many off-cycle clearance actions based on the findings in the inspection programs. For example, if the satellite or LiDAR identify areas that require additional trimming but are not due on the routine schedule, Bear Valley will dispatch the vegetation crews to clear these areas as a deviation from the routine cycle.

The routine trim plan is specifically intended to guarantee that all areas of the service territory are inspected and trimmed on a minimum periodic basis. Tree removals are prioritized by the level of risk that a tree is assigned. Higher risk fall-in trees are prioritized for removal or remediation as appropriate.

9.3.4 Updates

BVES has not made changes since the last WMP submission. While currently Bear Valley does not plan to update the initiative, Bear Valley is evaluating if the pre-inspection technique being employed can allow a shorter vegetation cycle time for the entire system (e.g., current cycle is 3 years but could potentially be reduced to 2 years).

9.4 Pole Clearing

9.4.1 Overview

Bear Valley has one initiative, Pole Clearing (VM_10) under this activity.

BVES has a vegetation management plan in place that meets or exceeds PRC 4292. Bear Valley's vegetation contractor executes the vegetation clearing efforts under the direction of BVES. The contractor's work is subject to BVES QA and QC checks. The goal of this plan is to proactively maintain vegetation, so it does not encroach electrical infrastructure, thereby preventing wildfires.

Base of Poles/Structures: For poles or structures that have non-exempt equipment per CALFIRE requirements, all flammable material and vegetation in a 10-foot radius around the base of the pole or structure shall be cut down and removed during each normal vegetation management cycle clearance visit. Exceptions per the effective California Power Line Fire Prevention Field Guide are authorized. BVES also clears around exempt poles. With the complete replacement of its traditional overhead expulsive fuses, nearly all of BVES's poles are now exempt from PRC 4292.

Bear Valley created the vegetation management plan with wildfire prevention in mind, collaborating with the City of Big Bear Lake, local Fire Departments, and the US Forest Service. The plan will be reviewed and updated on an as needed basis not to exceed three years, depending on changing conditions. The program includes three components: preventative vegetation management, corrective vegetation clearance, and emergency vegetation clearance. Each of these components needs to adhere to the designated specifications, such as with PRC 4292.

9.4.2 Procedures

Bear Valley has created a plan to complete pole clearing operations on all poles that are included in the Radford Line (sub-transmission). This line is in a remote forest area inaccessible by roads. These assets are in the HFTD Tier 3. This section of the service territory will have an annual clearing of all flammable material and vegetation in a 10-foot radius around the base of every pole.

Bear Valley is also evaluating recent concerns at other utilities where animal guards have been installed, animals enter the guards, ignite and fall to the ground, which potentially could set vegetation on the ground on fire. This concern can be mitigated by pole clearing and also ensuring guards are properly installed to prevent intrusion.

BVES is also proactively inspecting for any non-exempt equipment throughout the entire service territory during all asset inspections. When an inspector finds any non-exempt equipment, the operations supervisor is notified immediately and crews remove the non-exempt equipment. If the work cannot be completed in a timely manner, a vegetation crew is dispatched to the location to complete the pole clearing of all flammable material and vegetation within 10 feet of the pole.

9.4.3 Scheduling

The entire Radford Line (sub-transmission) will have pole clearing activities completed on every pole once a year. This work will be completed in the spring when conditions are safe enough for vegetation crews to enter the steep mountainous terrain. Bear Valley will also consider additional sections of lines that may need to have annual pole clearing operations.

9.4.4 Updates

Since the last WMP submission, Bear Valley has added the Radford Line to have annual pole clearing operations. This line is in the HFTD Tier 3 posing higher risk. Bear Valley has also created procedures on actions to be taken when non-exempt equipment is identified in the field. Finally, as discussed above, Bear Valley is evaluating other poles to be cleared to reduce the ignition risk posed by animals.

9.5 Wood and Slash Management

9.5.1 Overview

Bear Valley has one initiative, Wood and Slash Management (VM_11) under this activity.

Fuels reduction is a key element to wildfire mitigation. Bear Valley's vegetation clearance contractor clears vegetation and removes all vegetation waste and slash from the area every day. If the property owner wants the vegetation waste (for firewood, chipping, etc.), the contractor will assist the property owner in removing the vegetation waste from the rights-of-way for their use. Bear Valley also collaborates with the US Forest Service to remove trees near lines and remove the slash as agreed upon by the local US Forest Service Office.

9.5.2 Procedures

BVES understands the importance of removing wood and slash to help mitigate the total amount of fuels throughout the service territory. Therefore, all wood and slash that is created during vegetation management work or line work will be chipped and hauled away from the location. Per the contract with the vegetation management contractor, crews are responsible to remove all wood and slash and properly dispose of them to appropriate waste centers.

BVES routinely engages in fuels removal activities within the right-of-way to maintain forest health and target overgrown and scattered vegetation that potentially threaten to encroach within vegetation clearance specifications during vegetation management inspections.

BVES will continue to evaluate the effectiveness of its Wood Slash Management Program and make updates as needed.

9.5.3 Scheduling

With the entire Bear Valley service area being within HFTD, 100% of wood and slash created as a result of work completed by Bear Valley or its contractors is promptly and properly removed and hauled away from the work location. This ensures that Bear Valley is not leaving any debris that would increase fuel loading throughout the service area.

9.5.4 Updates

BVES has not made changes since the last WMP submission. Currently, Bear Valley does not plan any updates to this initiative.

9.6 Defensible Space

9.6.1 Overview

Bear Valley has one initiative, Substation defensible space (VM_12) under this activity.

BVES routinely performs inspections, brush mitigation, and maintenance work for each of its 13 substations. Monthly inspections occur where inspectors will look for any vegetation growth within a substation or vegetation that may be encroaching into a substation. BVES follows GO 174 and Public Resources Code section 4291 for substation defensible space.

9.6.2 Procedures

This initiative aligns with requirements under GOs 165 and 174 for inspections of substations and involves the removal of vegetation in and around substations that may result in contact with bare conductors. The initiative is intended to reduce the likelihood of vegetation contacting bare conductor; thereby, reducing the probability of ignition. Substation vegetation clearance work is conducted in response to periodic (monthly) visual site inspection of each substation. Based on inspection results, vegetation task orders are provided to a qualified contractor. The contractor performs corrective and emergent vegetation orders to fix clearance discrepancies that BVES discovers. If an order is designated as High Priority, the contractor must prioritize that work and make the correction immediately. The substation technician coordinates the work to provide safety escorts for work conducted within substations.

9.6.3 Scheduling

BVES schedules the first weed abatement and vegetation management work at the end of Q2 as part of the routine defensible space program. Vegetation work can also be requested after any substation inspection that occurs every month. All of Bear Valley's substations are located in HFTD Tier 2. Clearance work on all 13 substations is normally completed in one week total; therefore, there is no gain in risk prioritizing the work. All substation are held to the same standard. Depending on growth rates, BVES may direct additional vegetation clearing at the substations.

9.6.4 Updates

BVES has not made changes since the last WMP submission. Currently, Bear Valley does not plan to make any updates to this initiative.

9.7 Integrated Vegetation Management

9.7.1 Overview

BVES does not have any dedicated initiatives under this activity but does intend to move to making a dedicated effort toward this activity and to evolve it into an initiative.

Bear Valley currently does not utilize growth regulators or other chemical controls nor does Bear Valley plan to utilize these products.

Bear Valley does work with property owners on a case-by-case basis to replace fast growing non-native species with slow growing native species. Bear Valley will work with community partners, City of Big Bear Lake and Big Bear Fire Department, to develop a larger program with wide customer access to the program.

Each year Bear Valley hosts the premier Earth Day event attracting many members of the community. At the event, several organizations dedicated to responsible landscaping, establishing defensible space and educating the public on native species have booths where they are able to engage the public directly.

Bear Valley is also working closely with the US Forest Service, City of Big Bear Lake, County of San Bernardino, and Big Bear Fire Department to assist in managing fuels.

Bear Valley is also a member of the Inland Empire Fire Safe Alliance and Big Bear Fire Safe. These organizations promote educating the community on native species and responsible landscaping.

9.7.2 Procedures

Bear Valley currently does not have a formal initiative in this activity; therefore, formal procedures have not been established. The Wildfire Mitigation and Reliability Engineer has the lead on these integrated program outreach and collaboration efforts. During the period of this WMP, the Wildfire Mitigation and Reliability Engineer will develop procedures as these programs evolve and are implemented.

9.7.3 Scheduling

Bear Valley currently does not have a formal initiative in this activity; therefore, a schedule has not been developed. During the period of this WMP, the Wildfire Mitigation and Reliability Engineer will develop schedules as these programs evolve and are implemented.

9.7.4 Updates

BVES does not have any dedicated initiatives under this activity but does intend to move to making a dedicated effort toward this activity and to evolve it into an initiative.

9.8 Partnerships

9.8.1 Current and Future Partnerships

BVES does not currently have any formal partnerships that are associated with the vegetation management program; therefore, there is no information for Table 9-4. As Bear Valley pursues integrated vegetation management programs in the period of this WMP, Bear Valley will look to establish collaborative partnerships where feasible.

Table 9-4 Partnerships in Vegetation Management

Partnering Agency/ Organization	Activities	Objectives	Electrical Corporation Role	Anticipated Accomplishments
No Current Partnerships Exist	N/A	N/A	N/A	N/A

9.8.1.1 Overview

BVES does not currently have any formal partnerships that are associated with the vegetation management program.

9.8.1.2 Partnership History

BVES does not currently have any formal partnerships that are associated with the vegetation management program.

9.8.1.3 Future Projects

As Bear Valley pursues integrated vegetation management programs in the period of this WMP, Bear Valley will look to establish collaborative partnerships where feasible.

9.8.2 Past Partnerships

Bear Valley does not have any formal past vegetation management partnerships.

9.9 Activities Based on Weather Conditions

9.9.1 Overview

Bear Valley has one initiative, Emergency Response Vegetation Management (VM_13), under this activity.

Bear Valley consistently monitors the weather year-round with an emphasis on the higher risk months or the peak of fire season. BVES takes Red Flag Warnings and high fire threat days with the utmost caution. BVES requires the vegetation management contractors to change their operations to eliminate any chance of spark production during higher risk conditions. BVES also increases operational patrols to attempt to address any potential problems before they happen.

9.9.2 Procedures

Each day, a service area map displaying FPI and ignition risk for the sub-transmission and distribution system is circulated to the Engineering, Field Operations, Customer Service, and management.

Vegetation management crews have strict guidelines of what activities may be conducted on high fire risk days. Routine work is halted for the duration of the weather event. During Red Flag Events, in the event of emergency work, vegetation crews will attempt to complete the job without combustion motors such as chainsaws, attempt to reduce or modify fuels surrounding the jobsite, and have a dedicated fire watch to ensure no sparks or ignitions occur. Additionally on these high-risk days BVES may conduct additional patrols along circuits that have increased winds to identify any potential hazards that may be created by dangerous weather conditions. When the FPI is “High” or higher, at the direction of the Wildfire Mitigation and Safety Engineer and the Field Operations Supervisor, these additional patrols may be assigned.

Bear Valley has protocols in place that require on days where FPI is “High” or higher, employees and contractors are to:

- Cease using any spark-producing tools and equipment for circuits under consideration or in scope.
- Cease vegetation management work for circuits under consideration or in scope.
- Cease “high risk” energized line work for circuits under consideration or in scope.

Bear Valley’s small size allows the workforce to pivot to low-risk work on high fire threat days or conduct a training day for its staff.

Bear Valley’s vegetation management contractor has protocols in place for high fire threat weather. For example, when fire threat conditions exist, the vegetation contractor will:

- Evaluate the weather conditions to ensure they are safe to work in.
- A Dedicated Fire Watch must be assigned to the jobsite.
- There must be a trailer-mounted water tank or alternative water delivery method at the jobsite (120 gallons with 200 feet of hose).
- No chainsaw operations allowed – only hand saw use permitted.

9.9.3 Scheduling

The activities discussed in the previous section are triggered by FPI. Each day, a service area map displaying FPI and ignition risk for the sub-transmission and distribution system is circulated to the Engineering, Field Operations, Customer Service, and management. Bear Valley has protocols in place that require on days where FPI is “High” or higher, employees and contractors are to:

- Cease using any spark-producing tools and equipment for circuits under consideration or in scope.
- Cease vegetation management work for circuits under consideration or in scope.
- Cease “high risk” energized line work for circuits under consideration or in scope.

Additional patrols may be assigned based on the weather readings of the numerous weather stations from across the service territory and FPI at the direction of the Wildfire Mitigation and Safety Engineer and the Field Operations Supervisor. Areas that have more extreme weather will have priority.

9.9.4 Updates

Bear Valley implemented a Fire Potential Index in January 2024 and updated operational procedures to use FPI as a trigger parameter to operations to mitigate ignitions during high fire threat weather. Currently, Bear Valley does not plan any further updates to this activity.

9.10 Post-Fire Service Restoration

9.10.1 Overview

Bear Valley has one initiative, Post-fire Service Restoration (VM_14), under this activity.

While BVES has not experienced a significant fire, it remains prepared to respond quickly in the event an ignition source impacts adjacent vegetation or threatens public access. Post-fire restoration is important that it is conducted quickly and safely. BVES will continue conversations with CAL FIRE, other utilities, and vegetation contractors to develop a list of preparations that would be beneficial to have in place in the event the service area experiences a wildfire.

9.10.2 Procedures

Bear Valley will start all post-fire vegetation management activities when it is safe to do so and at the direction of the Incident Commander and in coordination with public safety first responders. Typically, this is after all fire suppression activities have been completed in the affected area. Once it is safe for crews to enter into areas that have been impacted by a fire, an inspection will be initiated to identify trees and vegetation that may be hazardous. These inspections are intended to identify trees and vegetation within striking distance to assets that were impacted by a wildland fire. Once the trees are identified as risks, vegetation crews will begin work on removing the trees.

Bear Valley's vegetation contractor has an emergency vegetation clearance scope of work, which includes completing maintenance on an as needed basis for any major disaster or emergency events. The contractor must mobilize as soon as possible to clear the vegetation at the direction of Bear Valley.

9.10.3 Scheduling

Bear Valley will start all post-fire vegetation management activities when it is safe to do so and at the direction of the Incident Commander and in coordination with public safety first responders. Typically, this is after all fire suppression activities have been completed in affected area.

9.10.4 Updates

Bear Valley will continue to work with CAL FIRE, other utilities, and vegetation contractors to develop procedures and checklist for this activity.

9.11 Quality Assurance and Quality Control

9.11.1 Overview, Objectives, and Targets

Bear Valley has one initiative, Vegetation Management Quality assurance / quality control (VM_15), under this activity. The objective of BVES's vegetation management

QA/QC program is to promote consistent and effective vegetation management action by establishing an oversight and audit process to review the work completed by employees or contractors, including packaging QA/QC information for input to decision-making and workforce management processes. This initiative includes the identification and actionable outcomes of deficiencies and inspection protocols executed in the field. This will support improvement of work outcomes, training of personnel involved in vegetation management, and applying lessons learned from internal and external evaluations and audits.

Table 9-5. Vegetation Management QA and QC Program Objectives below provides QA/QC program objectives and **Table 9-6. Vegetation Management QA and QC Activity Targets** provides QA/QC targets.

Table 9-5 Vegetation Management QA and QC Program Objectives

Initiative/Activity Being Audited	Tracking ID	Quality Program Type	Objective of the Quality Program
Detailed Inspection	VM_1	QA	To ensure that the field inspector is following BVES procedures for detailed inspections.
Patrol Inspection	VM_2	QA	To ensure that the field inspector is following BVES procedures for patrol inspections.
UAV HD Photography	VM_3	QC	To ensure contractor inspectors are identifying and flagging possible defect on assets.
LiDAR Inspection	VM_4	QC	To ensure that all possible encroachments are properly identified.
Third-Party Ground Patrol	VM_5	QC	To ensure contractor inspectors are identifying and flagging possible defect on assets.
Substation Inspection	VM_6	QA	To ensure that inspectors are conducting all inspection up to BVES standards.
Satellite Imaging	VM_7	QC	To ensure that all possible encroachments are properly identified.
Fall-in Mitigation and High Risk Species	VM_8	QC	To ensure that contractors completed trimming around assets to BVES standards.
Clearance	VM_9	QC	To ensure that contractors completed trimming around assets to BVES standards.
Substation Defensible Space	VM_12	QC	To ensure that contractors completed defensible space work around substations to BVES standards.

Table 9-6 Vegetation Management QA and QC Program Targets

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	[Year 3}: Sample Size	2028: % of Sample in HFTD	Confidence level / MOE	2026: Pass Rate Target	2027: Pass Rate Target	2028: Pass Rate Target
Detailed Inspection	# of Field Inspector	1	1	N/A	1	1	N/A	1	1	N/A	N/A	90%	90%	90%
Patrol Inspection	# of Field Inspector	1	1	N/A	1	1	N/A	1	1	N/A	N/A	90%	90%	90%
UAV HD Photography	Circuit Mile	205	205	100%	205	205	100%	205	205	100%	N/A	90%	90%	90%
LiDAR Inspection	Circuit Mile	205	205	100%	205	205	100%	205	205	100%	N/A	90%	90%	90%
Third-Party Ground Patrol	Circuit Mile	205	205	100%	205	205	100%	205	205	100%	N/A	90%	90%	90%
Substation Inspection	Substations Inspections	156	156	100%	156	156	100%	156	156	100%	N/A	90%	90%	90%
Satellite Imaging	Circuit Mile	205	205	100%	205	205	100%	205	205	100%	N/A	90%	90%	90%
Fall-in Mitigation and High-Risk Species	Circuit Mile	72	72	100%	72	72	100%	72	72	100%	N/A	90%	90%	90%
Clearance	Circuit Mile	72	72	100%	72	72	100%	72	72	100%	N/A	90%	90%	90%
Substation Defensible Space	Substations Defensible Space Work	13	13	100%	13	13	100%	13	13	100%	N/A	90%	90%	90%

9.11.2 QA/QC Procedures

Quality Assurance

In 2026, BVES aims to improve vegetation management inspection by conducting QA assessments and audits per BVES QA/QC procedures. BVES set a target to conduct four quarterly QA assessments and one annual program audit. Quarterly audits were conducted by the Wildfire Mitigation and Reliability Engineer, and the annual program audit by the contracted Forester.

The quarterly QA assessments include the following:

- Brief narrative on the status of the VM program, VM QC checks program and analysis or commentary on the metrics below as applicable.
- Number of trees trimmed as a result of the vegetation management program.
- Number of trees removed as a result of the vegetation management program.
- Number of Level 1 vegetation discrepancies identified.
- Number of Level 1 vegetation discrepancies resolved.
- Number of Vegetation Orders issued.
- Number of Vegetation Orders resolved.
- Any accidents, incidents, or near misses on the part of vegetation clearance personnel.
- Number of outages where vegetation made contact with power lines and caused the outage (break out those outages where vegetation clearance was in violation of standards).
- List of VM QC Checks performed (includes name of evaluator and date performed).
- List of significant findings from VM QC checks.
- Service area map showing where contractor worked in the quarter and where contractor will work in the next quarter.
- Where the contractor is in the vegetation cycle plan (e.g., percent complete).
- Corrective action taken on issues noted in previous Quarterly VM Program Assessments.
- Other items that would be useful to Management regarding vegetation management.

Additionally, an annual QA audit is conducted by the Forester in January of each year covering the previous calendar year. The audit provides a comprehensive review of the VM Program covering, at a minimum, the areas and questions specified in the following areas:

- VM Line Clearance

- Is the VM program effective at ensuring vegetation meets required clearance specifications?
- Is the VM program on track with the programmed schedule?
- Is the VM program effective in reducing vegetation contact with bare conductors?
- Are any changes to the VM clearance standards delineated in Section 3 necessary?
- Is the VM clearance contractor(s) executing work in accordance with the VM contract(s)?
- Are changes to the VM Contract Scope of Work needed?

- VM Inspections
  - Are VM inspections (patrol, detailed, LiDAR, etc.) being conducted in accordance with the Company's effective Wildfire Mitigation Plan?
  - Are the results of VM inspections being documented, tracked, and resolved in a timely manner in accordance with GO-95 Rule 18?
  - For each type of inspection performed, assess whether or not the inspection is effective and useful to assisting in achieving VM program objectives?
  - Should additional inspections be performed?
  - Is the scheduling of inspections appropriate or should the schedule be modified?
- VM QC Checks
  - Are VM QC Checks being performed in accordance with the requirements of this policy and procedure?
  - Are personnel performing VM QC Checks sufficiently knowledgeable and qualified to perform the checks?
  - Are VM QC Checks documented?
  - Are discrepancies identified in VM QC checks being tracked and resolved in a timely manner in accordance with GO-95 Rule 18?
  - Are VM QC Checks effective at identifying vegetation clearance issues?
  - Should modifications to Appendix B VM QC Check Instructions be made?
- VM Quarterly Reports
  - Are the VM Quarterly Reports being conducted?
  - Are the VM Quarterly Reports useful in providing management an assessment of the VM program?
  - Should changes be made to the content and/or periodicity of the VM Quarterly Reports?
- VM Program
  - Overall, were the Company's VM Program objectives achieved?
  - Are changes recommended to the VM Program Policy and Procedures?
  - Are changes in the Company's execution of its VM Program warranted?

<u>Pruning and Removal</u>

BVES conducts quality checks on vegetation clearance in two different ways. The first way BVES conducts QC checks is that the forester inspects 100% of all of the routine work that is conducted by the vegetation management crews. This QC process is meant to ensure that all vegetation has the required clearance from all assets that meet or exceed BVES standards. Additionally, if vegetation management crews miss any trees that may be hazards, the forester can document the missed finding. The other QC check is one where qualified staff inspects random areas where routine work has been completed. BVES set a target of 72 checks. QC reviews are to be conducted by qualified staff designated in the BVES vegetation management procedures manual.

QC reviews check the quality of recent vegetation clearance activities. Staff assigned vegetation management QCs receive a GIS map that illustrates the specific trees trimmed or removed and the pole numbers for each pole in each assigned QC area. The assigned staff then inspect the assigned area to determine whether the contractor cleared the vegetation surrounding the lines in accordance with BVES vegetation clearance specifications. The staff utilize a checklist to conduct the QC and document the results in an online application used to manage, document, and archive vegetation management QCs.

Discrepancies are forwarded to the vegetation management contractor to resolve. Additionally, the vegetation management QC application collects QC finding results and allows for analysis of potential systemic issues.

BVES conducts frequent QC checks of its vegetation contractor’s work execution. Discrepancies noted during QC checks, detailed inspections, patrols of overhead circuits, or other means, are generally forwarded to contracted resource via the Kintone Tree Trimming QC application provided by BVES. The contractor responds by marking whether completion of corrective actions is achieved through the software database. Additionally, the contractor documents the vegetation trimming activities performed in the utility right-of-way application to BVES’s Partner Software (part of BVES’ GIS suite). Discrepancies are designated and corrected as follows:

- Emergency (Priority 1) vegetation orders will be corrected immediately (or mitigated to reduce the priority level to at least Priority 2).
- Urgent (Priority 2) vegetation orders will be corrected within 30 days.
- Routine (Priority 3) vegetation orders will document non-urgent items that will be addressed during the regular tree trimming cycle.

BVES will monitor the results of its vegetation management QA/QC programs and implement improvements as warranted. A pass rate of 90% is designated for these checks. If the checks result in a score below 90%, the root causes are investigated by the Wildfire Mitigation & Reliability Engineer and Field Operations Supervisor and they are addressed with the vegetation contractor. A score below 90% is indicative of possible system issues. Depending on the severity of the issues, the Wildfire Mitigation & Reliability Engineer may pause vegetation clearance activities until the contractor resolves the root causes of the issue.

BVES will also exchange information with other utilities to determine best practices in vegetation management QA/QC for consideration in BVES's program. Furthermore, BVES is in the process of implementing vegetation management inspection software, which will enhance the ability to document QCs and perform QA on vegetation management inspections.

BVES QA and QC for Vegetation Inspection Programs

Detailed Inspection and Patrol Inspections (Tracking ID: VM_1 and VM_2)

QA/QC of distribution Detailed Inspections (VM_1) and Patrol Inspections (VM_2) conducted by Bear Valley's Field Inspector will include a supervisor's review and assessment of 100% of the findings identified during inspection. This will be conducted within 1 month of the inspection. The results of the review and assessment will be documented. In addition, each year 5% of the inspected facilities will be checked by a qualified inspector other than the person performing the original inspection as a QC check on these inspections. A pass rate of 90% is designated for these checks. If the checks result in a score below 90%, the root causes are investigated by the Wildfire Mitigation & Reliability Engineer and Field Operations Supervisor and they are addressed with the Field Inspector. The failing inspections are paused until the issues are resolved. Also, depending on the severity of the issues, all or part of the inspection may be directed to be conducted again by the Wildfire Mitigation & Reliability Engineer.

These changes will track pass/fail audit results, which will be communicated back to inspectors. Trends will be monitored and appropriate training will be delivered either individually or through annual refresher trainings administered to all qualified inspectors.

UAV HD Photography/Videography (Tracking ID: VM_3)

BVES conducts a combination of quality assurance and quality checks on 100% of findings created by the UAV Photography/Videography inspection. Once the data is delivered by the contractor, a quality assurance desktop review is conducted on all of the findings. Once the QA portion is completed the forester is sent into the field to conduct a visual QC to ensure that all findings are investigated and remediated. All of the findings sent to Bear Valley are QA/QC'd by Bear Valley's engineering/operations personnel. Any QA/QC discrepancies are sent to the contractor for further resolution and training.

LiDAR Inspection (Tracking ID: VM_4)

BVES quality checks 100% of findings created by the LiDAR inspection. This ensures that all 205 miles are inspected and all LiDAR findings are verified by the forester.

BVES conducts a combination of quality assurance and quality checks on 100% of findings created by the LiDAR inspection. Once the data is delivered by the contractor, a quality assurance desktop review is conducted on all of the findings. Once the QA portion is completed the forester is sent into the field to conduct a visual QC to ensure that all findings are investigated and remediated. All of the findings sent to Bear Valley are QA/QC'd by Bear Valley's engineering/operations personnel. Any QA/QC discrepancies are sent to the contractor for further resolution and training.

3rd Party Ground Patrol (Tracking ID: VM_5)

Bear Valley quality checks 100% of findings created by the 3rd party ground patrol inspection. This QC is conducted by the Bear Valley forester. Any QA/QC discrepancies are sent to the contractor for further resolution and training.

Substation Inspection (Tracking ID: VM_6)

BVES conducts quality assurance checks on 100% of substation inspections. Once a substation is inspected, the reports are submitted to the Wildfire Mitigation and Reliability Engineer and reviewed to ensure that the inspector followed the appropriate BVES procedures. Any QA/QC discrepancies are reviewed with the substation technician for further resolution and training. Additionally, if any vegetation findings are noted, mitigation activities will be scheduled.

Satellite Imaging Inspection (Tracking ID: VM_7)

BVES quality checks 100% of findings created by the satellite inspection. This QC is conducted by the Bear Valley forester. Any QA/QC discrepancies are sent to the contractor for further resolution and training.

Substation Defensible Space (Tracking ID: VM-12)

BVES conducts QC checks on all substations that have defensible space work completed. Following the completion of vegetation management work at a substation a BVES substation technician will go to 100% of the locations where work was completed and perform an inspection. This inspection checks to make sure that the contractor completed all defensible space work to BVES standards.

9.11.3 Sample Sizes

Bear Valley uses 100% as its sample size for vegetation management QA/QC procedures. BVES is a very small utility that deals with small data sets. This is the most effective way BVES is able to QA/QC the many vegetation management programs.

9.11.4 Pass Rate Calculation

BVES uses historical data to create the proper pass rate for each QA/QC program. Bear Valley currently uses 90% pass rate. Scores below 90% are indicative of possible system issues and must be investigated to determine the extent of the issues, root causes, and corrective actions. All findings are corrected regardless of score.

9.11.5 Other Metrics

BVES conducts cross checks across all of the different inspection and QA/QC programs to identify any trends. Cross checks involve comparing the results of the different inspections conducted and noting any differences in results (e.g., why did one inspect pick up a discrepancy but another did not?, etc.). This helps BVES to evaluate the quality and effectiveness of each inspection type and the QA/QC process and effectiveness.

9.11.6 Documentation of Findings

BVES utilizes a tree trimming QC program, Kintone Tree Trimming, as part of its internal quality control for vegetation management activities. This database provides several fuel characteristics that are tracked for record-keeping and presents the number of trees targeted for remediation with those that have passed a QC review and those that have failed. This results in an efficiency rating based on parameters that align with General Order 95 Rule 35 and BVES's enhanced vegetation management practices.

For the asset inspections the QA/QC findings are documented on Excel sheets. The Excel sheets are direct exported reports from the database in which the inspections were documented. The QC/QA inspector takes the Excel sheets and confirms all of the findings from the inspection. These excel sheets are then returned to the Wildfire Mitigation and Reliability Engineer for analysis.

9.11.7 Changes to QA/QC Since Last WMP and Planned Improvements

Bear Valley is transitioning to a new vegetation enterprise system under initiative Vegetation Management Enterprise System (ENT_2). The new system, Intelligent Vegetation Management System (IVMS), will enable improved QA/QC audits and documentation.

9.12 Work Orders

Bear Valley has one initiative, Vegetation Management Open Work Orders (VM_16), under this activity.

9.12.1 Priority Assignment

BVES uses GO 95 Rule 18 requirements as guidance for managing and prioritizing open work orders. Work Orders are given priority levels and associated timeframes for completion. In 2025, BVES will move to using AiDASh IVMS (Enterprise System) to track all open vegetation work orders. When a discrepancy is identified by the vegetation inspector, a work order is created and a severity level (Level 1, 2, or 3 in accordance with GO 95 Rule 18) is applied. The severity will dictate the timeframe for remediation. For vegetation-related discrepancies, timeframe and example situations are as follow:

- Level 1 – Immediate Action – Vegetation Order Issued to Contractor for Immediate Action
    - Vegetation contacting, nearly contacting or arcing to high voltage conductor, vegetation contacting low voltage conductor and compromising structure, etc.
- Level 2 – Action within 30 days – Vegetation Order Issued to Contractor for Action within 30 days
    - Vegetation within 48 inches of high voltage lines, vegetation causing strain or abrasion on low voltage conductor, tree or portions of tree that are dead, rotten, or diseased that may fall into power lines, etc.
- Level 3 – Non-urgent Normal Cycle Action – Vegetation Order issued to Contractor for Action during the next normal vegetation cycle

9.12.2 Backlog Elimination

BVES prioritizes open work orders first by level of severity defined by GO 95 Rule 18, then by HFTD Tier (all of the Bear Valley service area is in the HFTD). For example, an HFTD Tier 3 Level 2 work order is prioritized over an HFTD Tier 2 Level 2 work order. Finally, BVES prioritizes work orders within each level and HFTD area by higher risk circuits. For example, Level 2 work orders within the HFTD 2 area are prioritized based on the level of risk circuits.

BVES does not typically have any backlog of work orders with routine work. Backlog of work orders usually occur during vegetation inspection programs like LiDAR and Satellite imaging inspections. In the case where a backlog of work orders occur, additional crews will be assigned to mitigate the findings. This ensures that any outstanding work orders will be completed as soon as possible.

9.12.3 Trends

All of Bear Valley's service area is in the HFTD. **Table 9-7. Number of Past Due Vegetation Management Work Orders Categorized by Age and HFTD Tier** and **Table 9-8. Number of Past Due Vegetation Management Work Orders Categorized by Age and Priority Levels** provide past due vegetation management work orders.

Table 9-7 Number of Past Due Vegetation Management Work Orders Categorized by Age and HFTD Tier

HTFD Area	0-30 Days	31-90 Days	91-180 Days	181+ Days
Non-HFTD	0	0	0	0
HFTD Tier 2	44	0	0	0
HFTD Tier 3	0	0	0	0

Table 9-8 Number of Past Due Vegetation Management Work Orders Categorized by Age and Priority Levels

Priority Level	0-30 Days	31-90 Days	91-180 Days	181+ Days
Priority 1	0	0	0	0
Priority 2	44	0	0	0
Priority 3	0	0	0	0

BVES has identified a trend on past due vegetation management work orders because of the numerous inspection programs that are conducted on an annual basis. This is most evident on the LiDAR inspection because the entire service territory is inspected in under a month. This has caused a large number of encroachments to be reported across the entire service territory all at once. With the identification of this trend BVES has been able to allocate crews to better manage workload. BVES now dedicates more crews to these inspection programs to ensure that a backup does not occur.

9.13 Workforce Planning

Bear Valley has one initiative, Vegetation Management Open Work Orders (VM_17), under this activity. Table 9-9. Vegetation Management Qualifications and Training provides a listing of personnel involved in vegetation management along with qualifications and training.

Table 9-9 Vegetation Management Qualifications and Training

Worker Title	Minimum Qualifications for Target Role	Applicable Certifications	# of Electrical Corporation Employees with Min Quals	# of Electrical Corporation Employees with Special Certifications	# of Contracted Employees with Min Quals	# of Contractor Employees with Applicable Certifications	Total # of Employees	Reference to Electrical Corporation Training / Qualification Programs
Forester	One year of arboriculture experience or degree in relevant field	ISA Certified Arborist	0	ISA Certified Arborist Utility Specialist-1	1	1	1	N/A
Tree Trim General Foreman/Supervisor (Contractor)	5 years of line clearance tree pruning experience in a Foreman role Line clearance Certification Current California Driver License General Computer knowledge	Line-clearance qualified tree-trimmer	0	N/A	3	0	3	N/A
Tree Trim Groundsman	One year of arboriculture experience or degree in relevant field	Strong work ethic Current California Driver License (Class B permit) General computer skills	0	N/A	6	0	6	N/A
Geospatial Lead Analyst	8 years of GIS and Remote Sensing Experience Strong Quality Control and Detail Advanced Knowledge of LiDAR Sensors and Data Advanced GIS Skills and Problem Solving	ASPRS Certified Remote Sensing Technologist	0	N/A	1	0	1	N/A
Geospatial Technician	Solid Understand of GIS and Remote Sensing Science Strong Attention to Detail Strong Computer Skills Work Independently	N/A	0	N/A	1	0	1	N/A
Utility Systems Specialist Inspector/Lead Inspector	Overhead Distribution and/or Transmission distribution inspection experience (2-year min) Identification of all overhead equipment Current Driver License Computer and GIS mapping experience	NESC and ANSI Inspection experience (1-year min) Red Cross FA/CPR certified Wildfire Training Registered	0	N/A	2	0	2	N/A

Field Inspector	Three years of Journeyman Lineman or above experience. Experience inspecting overhead and underground facilities. Class C California Driver's License	IBEW Journeyman Lineman Registered	1	N/A	0	0	1	N/A
Utility Engineer & Wildfire Mitigation Supervisor	Bachelor's Degree in an engineering field or a technical discipline required. Eight years of planning, construction, or engineering experience including four years of administrative and supervisory experience. Utility experience preferred. Work experience in an area with strong compliance regimes. Experience interacting with utility regulators and knowledge of regulatory processes preferred	Professional Engineer license in California required. If not held, must obtain within 2 years of employment	1	N/A	0	0	1	N/A
Wildfire Mitigation and Reliability Engineer	Bachelor of Science degree in Engineering, Mathematics, Physics, or other related technical discipline. Prior electric utility experience preferred. Understanding of statistical analysis and probabilistic methods preferred.	N/A	1	N/A	0	0	1	N/A

9.13.1 Recruitment

Currently, Bear Valley is fully staffed with appropriately qualified personnel to meet all of its vegetation management and inspection requirements. Bear Valley retains a certified arborist forester embedded in its staff and contracts out pruning activities and the following inspection activities:

- UAV HD Photography/Videography Inspections (VM_3)
- LiDAR Inspections (VM_4)
- 3rd Party Ground Patrol Inspections (VM_5)
- Satellite Imaging Inspections (VM_7)

Currently, Bear Valley does not have any partnerships with colleges or universities.

9.13.2 Training and Retention

Specific training requirements are provided in **Table 9 9 Vegetation Management Qualifications and Training**. Starting in 2025, Bear Valley will be conducting annual vegetation management and clearances training for all staff involved in vegetation programs and staff that may encounter vegetation issues. The training will be led by the Wildfire Mitigation & Reliability Engineer and the forester. Field Operations and Engineering staff will all be required to attend this training. This training will be monitored by the President.

10. Situational Awareness and Forecasting

Each electrical corporation's WMP must include plans for situational awareness.[2]

10.1 Targets

Table 10-1 Situational Awareness Targets by Year below provides the targets for each initiative in the Situational Awareness and Forecasting category.

10.1.1 Qualitative Targets

Initiatives that have qualitative targets in the Situational Awareness and Forecasting category are listed in **Table 10-1 Situational Awareness Targets by Year** below.

10.1.2 Quantitative Targets

Initiatives that have quantitative targets in the Situational Awareness and Forecasting category are listed in **Table 10-1 Situational Awareness Targets by Year** below.

[2] Pub. Util. Code §§ 8386(c)(2)-(5).

Table 10-1 Situational Awareness Targets by Year

Initiative	Quantitative or Qualitative Target	Activity (Tracking ID #)	Previous Tracking ID, if applicable	Target Unit	2026 End of Year Total / Completion Date	% Risk Reduction for 2026	2027 Total / Status	% Risk Reduction for 2027	2028 Total / Status	% Risk Reduction for 2028	Three- Year Total	Section; Page number
Environmental monitoring systems	Quantitative	Advanced weather monitoring and weather stations (SAF_1)	SAF_1	Number of Weather Stations Serviced	20	4.34%	20	4.34%	20	4.34%	60	10.2; p.229
Environmental monitoring systems	Qualitative	Integrate Environmental Monitoring Network as a standard feed into the Distribution Management Center. Advanced weather monitoring and weather stations (SAF_1)	SAF_1	N/A	In progress; October 2026	N/A	Completed; October 2027	N/A	Completed; October 2027	N/A	N/A	10.2; p.229
Grid monitoring systems	Quantitative	Fault Indicator Serviced (SAF_2)	SAF_2	% of Installed FI's Serviced	100%	3.43%	100%	3.43%	100%	3.43%	3	10.3; p.231
Grid monitoring systems	Qualitative	Integrate FIs as a standard feed into the Distribution Management Center. Fault Indicators (SAF_2)	SAF_2	N/A	In progress; October 2026	N/A	In progress; October 2027	N/A	Completed; October 2028	N/A	N/A	10.3; p.231
Grid monitoring systems	Quantitative	Online Diagnostic System (SAF_3)	SAF_3	Number of circuits installed on per year.	1	4.34%	N/A	N/A	N/A	N/A	1	10.3; p.231
Grid monitoring systems	Qualitative	Conduct annual review and evaluation of Online Diagnostic system database of system detections. Online Diagnostic System (SAF_3)	SAF_3	N/A	Annual review and evaluation completed; December 2026	N/A	Annual review and evaluation completed; December 2027	N/A	Annual review and evaluation completed; December 2028	N/A	N/A	10.3; p.231
Ignition detection systems	Quantitative	Autonomous Monitoring of Power Line Infrastructure (SAF_4)	SAF_4	% of Installed Sensors Serviced	100%	4.65%	100%	4.65%	100%	4.65%	3	10.4; p.235
Ignition detection systems	Qualitative	Integrate issue as a standard feed into the Distribution Management Center. Autonomous Monitoring of Power Line Infrastructure (SAF_4)	SAF_4	N/A	In progress; October 2026	N/A	Completed; October 2027	N/A	Completed; October 2027	N/A	N/A	10.4; p.235
Ignition detection systems	Quantitative	ALERTWildfire Cameras (SAF_5)	SAF_5	Number of ALERTWildfire Cameras Evaluated by BVES in Operability and Coverage Review	15	3.12%	15	3.12%	15	3.12%	45	10.4; p.235

Ignition detection systems	Qualitative	Provide assistance as requested by ALERT Wildfire Consortium to maintain, upgrade, and/or expand ALERT Wildfire Cameras covering BVES Service Area. ALERTWildfire Cameras (SAF_5)	SAF_5	N/A	In progress; October 2026	N/A	In progress; October 2027	N/A	Completed; October 2028	N/A	N/A	10.4; p.235
Weather forecasting	Quantitative	Weather forecasting (SAF_6)	SAF_6	Percent Time Each Year Weather Stations are Operational	85%	4.34%	85%	4.34%	85%	4.34%	85%	10.5; p.241
Weather forecasting	Qualitative	Maintain WFA-E Capability and Weather Consultant Coverage for Each Year. Weather forecasting (SAF_6)	SAF_6	N/A	Completed annual review of WFA-E Capability and Weather Consultant Coverage; December 2026	N/A	Completed annual review of WFA-E Capability and Weather Consultant Coverage; December 2026	N/A	Completed annual review of WFA-E Capability and Weather Consultant Coverage; December 2026	N/A	N/A	10.5; p.241
Fire potential index	Quantitative	Fire potential index (SAF_7)	SAF_7	FPI Model Domain Size in Mi^2	3168	4.65%	3168	4.65%	3168	4.65%	9504	10.6; p.244
Fire potential index	Qualitative	Integrate FPI as a standard feed into the Distribution Management Center. Fire potential index (SAF_7)	SAF_7	N/A	In progress; October 2026	N/A	Completed; October 2027	N/A	Completed; October 2027	N/A	N/A	10.6; p.244

10.2 Environmental Monitoring Systems

Bear Valley has one initiative, Advanced Weather Monitoring and Weather Stations (Tracking ID: SAF_1) in this section.

10.2.1 Existing Systems, Technologies, and Procedures

Table 10-2. Environmental Monitoring Systems lists Bear Valley's environmental monitoring systems.

Table 10-2 Environmental Monitoring Systems

System	Measurement/ Observation	Frequency	Purpose and Integration
Weather stations	Air Temperature Wind Velocity & Direction (Steady & Gust) Relative Humidity Barometric Pressure Precipitation	60 observations/hour	Improved weather monitoring and forecasting Model Validation SCADA Connected

Advanced Weather Monitoring and Weather Stations (Tracking ID: SAF_1)

Weather stations are a key component in situational awareness and wildfire risk mitigation strategies. In 2021, Bear Valley completed the installation of all 20 weather stations manufactured by Orion. These stations measure temperature, relative humidity, barometric pressure, wind direction and speed, and precipitation.

These sensors communicate over wireless cellular communications to help Bear Valley obtain service-territory-specific data and information at one-minute interval recordings. Currently, the weather station data is captured on its own platform. The data gathered from the weather stations has also been integrated directly into the Technosylva WFA-E model.

Bear Valley assesses that the 20 weather stations will provide sufficient coverage of its service area. **Figure 10-1 BVES Weather Station Locations** below illustrates the locations of the weather stations.

Figure 10-1 BVES Weather Station Locations

BVES has developed a maintenance plan in which two (2) to three (3) weather stations per month undergo maintenance and calibrations. The annual target is to service each weather station once per year; therefore, the annual target is to service all 20 weather stations each year. When corrective maintenance is performed that could affect the calibration of the weather station, the weather station will have the annual maintenance and calibration performed on it prior to returning it to service. This plan allows for timely maintenance activities while maximizing the number of operating weather stations. Sensors will be replaced as specified by the vendor. Records are maintained that include:

- The station name and location.
- The reason for the inability to conduct maintenance and/or calibration.
- The length of time since the last maintenance and calibration.
- The number of attempted but incomplete maintenance or calibration events for these stations in each calendar year.

Additionally, all the weather station's data is checked at least monthly. If a weather station is not operating properly, it will undergo non-scheduled corrective maintenance.

The operational status of the weather stations is briefed to management at the weekly management meeting.

10.2.2 Evaluation and Selection of New Systems

Bear Valley evaluates the need for additional environmental monitoring systems as follows:

- Regarding expansion of its existing environmental monitoring systems, Bear Valley takes input from its primary users, Field Operations Staff.
- Bear Valley's management periodically reviews environmental monitoring programs and examines how systems can be improved as part of its continuous improvement process.
- If an expansion is contemplated, Bear Valley would assess the risk reduction benefit of the expansion. Currently, this would be done with the SMJU 7x7 Risk Based Decision Making Model.
- Regarding new systems, Bear Valley attends monthly WMP Joint IOU meetings and conferences and workshops that discuss wildfire mitigation. At these venues, Bear Valley is exposed to new systems. The new systems are reviewed by BVES management with user input as part of its continuous improvement process.
- If a new system is contemplated, Bear Valley will gather as much information on the system as possible, alternatives to the system, user experiences on the system and then will make a risk-based analysis on the benefit of the system. Currently, this would be done with the SMJU 7x7 Risk Based Decision Making Model.

10.2.3 Planned Improvements

Bear Valley currently does not plan to expand or implement new environmental monitoring systems.

10.2.4 Evaluating Activities

Bear Valley evaluates its environmental monitoring systems as follows:

- Bear Valley takes input from its users, which are Field Operations Staff, its weather consultant, and risk modeling contractor, Technosylva. This input is important to ensure the system is providing the user the required accuracy and information to support their activities and obligations.
- Bear Valley also reviews the reliability of the system by evaluating maintenance records and performance.

10.3 Grid Monitoring Systems

Bear Valley has two initiatives, Fault Indicators (Tracking ID: SAF_2) and Online Diagnostic System (Tracking ID: SAF_3), in this section.

10.3.1 Existing Systems, Technologies, and Procedures

Table 10-3. Grid Operation Monitoring Systems lists Bear Valley's grid operation monitoring systems.

Table 10-3 Grid Operation Monitoring Systems

System	Measurement/ Observation	Frequency	Purpose and Integration
Fault Indicators Serviced	Indication of fault on an electrical line or circuit	Real-Time	Allow for BVES to reduce risk of ignition or spark by reducing time to locate and isolate fault. BVES has installed 162 on the system and 60 are connected to SCADA.
EGM Meta-Alert System	Fault Monitoring due fire, grounding, or third-party impact Electrical current, voltage Waveform, harmonics	Real-Time	Real-time monitoring of Baldwin, North Shore, Boulder Circuits

Fault Indicators (SAF_2)

This initiative maintains 162 fault indicators (FIs) installed throughout the entire BVES sub-transmission and distribution systems. FIs are devices installed on overhead power lines in electric power distribution systems to detect and indicate the occurrence of faults. They are installed at specific distances along a circuit and at major branch lines so that when a fault occurs, the location of the fault zone (where the fault occurred) is minimized, thereby reducing time to locate and identify the specific fault and, therefore, restore service to affected customers. FIs provide a visual indication on which side of the FI the fault occurred on. Therefore, responding crews look for the portion of the circuit in which the FIs have "sandwiched" the fault. Some FIs also have the capability to be connected to the SCADA network, which allows remote identification of the fault zone. This further reduces response time in localizing a fault since the crews would be directed to roll their truck directly to the fault zone rather than the faulted circuit. Because FIs allow crews to locate and arrive at the fault location significantly faster, they are more likely to identify a faulted situation and ignition in a timelier manner and have a greater opportunity to reduce the risks of a wildfire. 60 FIs have been connected to SCADA.

Online Diagnostic System (SAF_3)

This initiative installs continuous monitor sensors to provide usable grid insight information that is measured, reported, and documented. Analytics help to ensure that current and future irregularities can be corrected before a problem arises. This will help to ensure safety, reliability, cost control, and customer satisfaction. The system is designed to pinpoint irregularities, which may be due to degrading/imminent hardware failures, as well as identify objects, such as vegetation, contacting the lines. This will assist BVES in rapidly inspecting potential problems before they develop into an ignition source. This initiative intends to help mitigate the potential for fire exposure of high-risk circuits not poised to be replaced with covered conductors in the immediate future due to the current program schedule or other constraints. The system was installed on the Baldwin Circuit (34 kV) and on the North Shore Circuit (4 kV) in June 2023 and installed on the Boulder Circuit (4 kV) in December 2024. BVES plans to install the system on 1 circuit per year.

Recloser Operations

Per Bear Valley's 2023-2025 WMP initiatives, by the end of 2025 BVES will have automated 31 switches/field devices into BVES Supervisory Control and Data Acquisition (SCADA) system and 11 of these devices are auto-reclosers (ARs). The SCADA system has the capability to detect AR operations and capture data that is used to provide real-time fault information and assist in diagnosing system problems during and after events. This improves grid reliability, enhances response times to outages, optimizes resource allocation, and improves public safety. The Switch and Field Device Automation (GD_8) initiative will connect additional ARs during the period of this WMP. Section 8.7.1. Equipment Settings to Reduce Wildfire Risk provides Bear Valley's operating policy for ARs.

10.3.2 Evaluation and Selection of New Systems

Bear Valley evaluates the need for additional grid operation monitoring systems as follows:

- Regarding expansion of its existing grid operation monitoring systems, Bear Valley takes input from its primary users, Field Operations Staff.
- Bear Valley's management periodically reviews grid operation monitoring systems and examines how systems can be improved as part of its continuous improvement process.
- If an expansion is contemplated, Bear Valley would assess the risk reduction benefit of the expansion. Currently, this would be done with the SMJU 7x7 Risk Based Decision Making Model.
- Regarding new systems, Bear Valley attends monthly WMP Joint IOU meetings and conferences and workshops that discuss wildfire mitigation. At these venues, Bear Valley is exposed to new systems. The new systems are reviewed by BVES management with user input as part of its continuous improvement process.
- If a new system is contemplated, Bear Valley will gather as much information on the system as possible, including alternatives to the system and user

experiences with the system, and then will make a risk-based analysis on the benefit of the system. Currently, this would be done with the SMJU 7x7 Risk Based Decision Making Model.

10.3.3 Planned Improvements

Fault Indicator Service (SAF_2): BVES will schedule annual maintenance to service existing FIs, which includes upgrades/replacement as needed to ensure FIs are fully functional and communicating with BVES's SCADA system. BVES may add additional FIs to the system based on input from Field Operations.

Online Diagnostic System (SAF_3): In 2026, BVES plans to install an additional EGM Meta-Alert system on one more circuit, currently planned for the Clubview Circuit. BVES will schedule an annual maintenance program to service the existing EGM system and continue to collaborate with EGM to improve their system and interface into BVES's SCADA system.

Recloser Operations will be expanded through the Switch and Field Device Automation (GD_8) initiative, which will connect additional ARs during the period of this WMP.

10.3.4 Evaluating Activities

BVES evaluates the efficacy of its grid operation monitoring program as follows:

- Bear Valley takes input from its users, which are Field Operations Staff. This input is important to ensure the grid operation monitoring program is providing the user the required accuracy and information to support their activities and obligations.
- Bear Valley also reviews the reliability of the system by evaluating maintenance records and performance.
- **Real-Time Monitoring:** Utilizes SCADA system to gather real-time data throughout the circuits. The data will be continuously collected and updated to allow for real-time decision-making.
- **Data Granularity:** Bear Valley ensures the data collected is high-quality, reliable, and sufficiently granular (at the level of circuits, substations, or specific equipment) to identify trends and potential issues.
- **Automated Alerts:** Utilizes automated systems to detect anomalies, faults, or potential issues in real-time, ensuring that operators can take corrective action quickly.
- **Maintenance:** Works with vendors on potential system upgrades, monitoring system to improve accuracy, response times, and predictive capabilities.

10.4 Ignition Detection Systems

Bear Valley has two dedicated initiatives, Autonomous Monitoring of Power Line Infrastructure (Tracking ID: SAF_4) and ALERT Wildfire Cameras (Tracking ID: SAF_5) in this section. Additionally, fire growth potential software is included in the wildfire risk modeling software suite, Technosylva's Wildfire Analyst Enterprise (WFA-E), that Bear Valley utilizes.

10.4.1 Existing Ignition Detection Sensors and Systems

Satellite Infrared Imagery

BVES is not currently pursuing or planning on utilizing satellite infrared imagery for ignition detection. BVES's service area is small and other systems are available to detect ignitions; therefore, BVES has determined to not pursue satellite infrared imagery.

HD Video Cameras

Autonomous Monitoring of Power Line Infrastructure (SAF_4)

In 2023, BVES implemented a pilot program to install two (2) HD cameras with AI sensor technology that continuously monitor the pole and associated line in partnership with Green Grid Inc. The iSIU system provides continuously automated monitoring of asset physical condition as well as ignition monitoring. The system consists of camera units (nodes) that contain AI sensors, communication modules, processors, and power supply. These nodes allow for autonomous monitoring of the power line infrastructure and can advise the remote maintenance, inspections, or operator crews on equipment status and potential hazardous events. The program will increase real time data as well as reduce operational costs, and human and environmental risk.

In 2025, BVES plans to install 15 iSIU system cameras, which will provide additional coverage on the Radford Circuit. Most of the Radford Circuit is located in the HFTD Tier 3, with a small portion in the HFTD Tier 2. Additionally, most of the circuit is in the US Forest Service area and not accessible by roads. Without this system, if an ignition occurs without the circuit relaying, it would likely go undetected until it grows into a fire.

General location of detection sensors (e.g., HFTD or entire service territory): 17 HD cameras with AI sensor technology, 15 will be installed on Radford Circuit (HFTD Tier 3) providing full coverage, 1 installed on Northshore Circuit (pilot program) and 1 installed on Boulder Circuit (pilot program).

Resiliency of Sensor Communication Pathways: The Northshore and Boulder Circuit HD cameras are connected through a cellular communication network connecting to the iSIU system cloud data management server. iSIU system monitors and maintains the connectivity of the cameras. The Radford Circuit HD cameras will be connected to Bear Valley's fiber optic network and then upload to the iSIU system cloud data management server. Bear Valley is able to access and view the status of the HD cameras at any time.

Integration of Sensor Data into Machine Learning or AI Software: The iSIU system utilizes AI sensor technology, which allows continuous real-time asset and vegetation inspection and monitoring for ignition risk insight and ignition detection.

Role of Sensor Data in Risk Response: The iSIU system utilizes AI sensor technology to provide early detection, alerting of potential or actual failures and ignition events to prevent utility ignited catastrophic wildfires.

False Positives Filtering: Once BVES staff receive an alert notification, they view the cameras for situational awareness and determine what action is necessary on the part of BVES operational staff. If action is required, implementation of BVES operational response protocols would be taken. If no action is required, BVES would dismiss the alert.

Time between Detection and Confirmation: The system is new, and the current 2 HD cameras have not alerted because no faults have occurred. Bear Valley has tested the alert system (text and email), and it is automatic and instantaneous.

Security Measures for Network-Based: The iSIU manufacturer and service provider maintains and secures data feeds. They provide BVES users with login and password to access the cameras on their dedicated cloud based secure website.

ALERT Wildfire Cameras (SAF_5)

In partnership with the University of California, San Diego (UCSD) ALERTCalifornia (formerly AlertWIdlfire) network, BVES utilizes the network’s 15 HD cameras in 7 locations, providing full visibility into the Big Bear Valley. Continuous live feeds help inform BVES, Big Bear Fire Department, San Bernardino Fire Department, San Bernardino Office of Emergency Services, CAL FIRE and other agencies with fast information gathering for the ability to confirm smoke/fire location and direction of growth in Big Bear Valley. The information is critical for BVES to protect assets and PSPS decision-making, as well as for Fire Departments to evaluate and dispatch resources quickly. BVES continues to work with stakeholders to ensure the HD ALERTCalifornia network has sufficient cameras. The cameras provide live high-definition video feed, and infrared detection capability is being incorporated into the system.

The HD Cameras that BVES, in partnership with UCSD, Big Bear Fire Department, San Bernardino Fire Department, San Bernardino Office of Emergency Services, and CAL FIRE, has strategically placed around its service territory are a key component in situation awareness, specifically in instances of elevated fire risk. The HD Cameras provide visual awareness of the territories adjacent to electrical assets and maintain live accounts of risk drivers during hazardous weather conditions. The cameras owned by UCSD (supported by BVES) will also contribute to the Southern California system, which comprises a shared network of utility, academic, and fire response cameras to provide coverage of live feeds to monitor conditions and assist emergency event awareness. During high-threat conditions, BVES deploys personnel to supplement camera information with observations by qualified personnel. BVES currently has the ALERTCalifornia cameras on an as-needed basis maintenance schedule. There is no current tracking associated with the cameras, and BVES plans to track this in more detail in future WMP submissions.

General location of detection sensors (e.g., HFTD or entire service territory): 15 HD cameras in 7 locations currently provide full coverage within and beyond BVES's service area. The cameras are located at selected mountain peaks, hilltops, and a radio station antenna. These locations were selected in partnership with UCSD, Big Bear Fire Department, San Bernardino Fire Department, San Bernardino Office of Emergency Services, and CAL FIRE.

Resiliency of Sensor Communication Pathways: HD cameras are connected through radio/cellular communication network connecting to UCSD's secured network protocols. UCSD monitors and maintains the connectivity of the HD cameras. Partnering with UCSD allows BVES to access and view the status of the cameras. BVES assists UCSD in maintaining the communications equipment and provides on-site checks when requested by UCSD.

Integration of Sensor Data into Machine Learning or AI Software: The ALERTCalifornia HD cameras use AI to detect fires. When the AI spots a potential fire on ALERTCalifornia's network of cameras, the system alerts firefighters and provides a percentage of certainty, and estimated location for the incident.

Role of Sensor Data in Risk Response: The ALERTCalifornia HD cameras employ infrared FLIR sensor technology and AI technology and provide continuous live feeds. System send alerts for potential smoke/fire locations to San Bernardino County Fire Department resources and provide situational awareness allowing respective parties to better respond to alerts.

False Positives Filtering: Once BVES staff receive an alert notification, they view the cameras for situational awareness and determine what action is necessary on the part of BVES operational staff. If action is required, implementation of BVES operational response protocols would be taken. If no action is required, BVES would dismiss the alert.

Time between Detection and Confirmation: BVES does not keep records of alert notifications from ALERTCalifornia HD cameras. To date, Bear Valley has not had an ignition or an alert from ALERTCalifornia HD cameras.

Security Measures for Network-Based: UCSD maintains and secures data feeds. HD cameras are accessible by BVES through the UCSD provided website, https://AlertCA.live which is available to the public.

Infrared Cameras

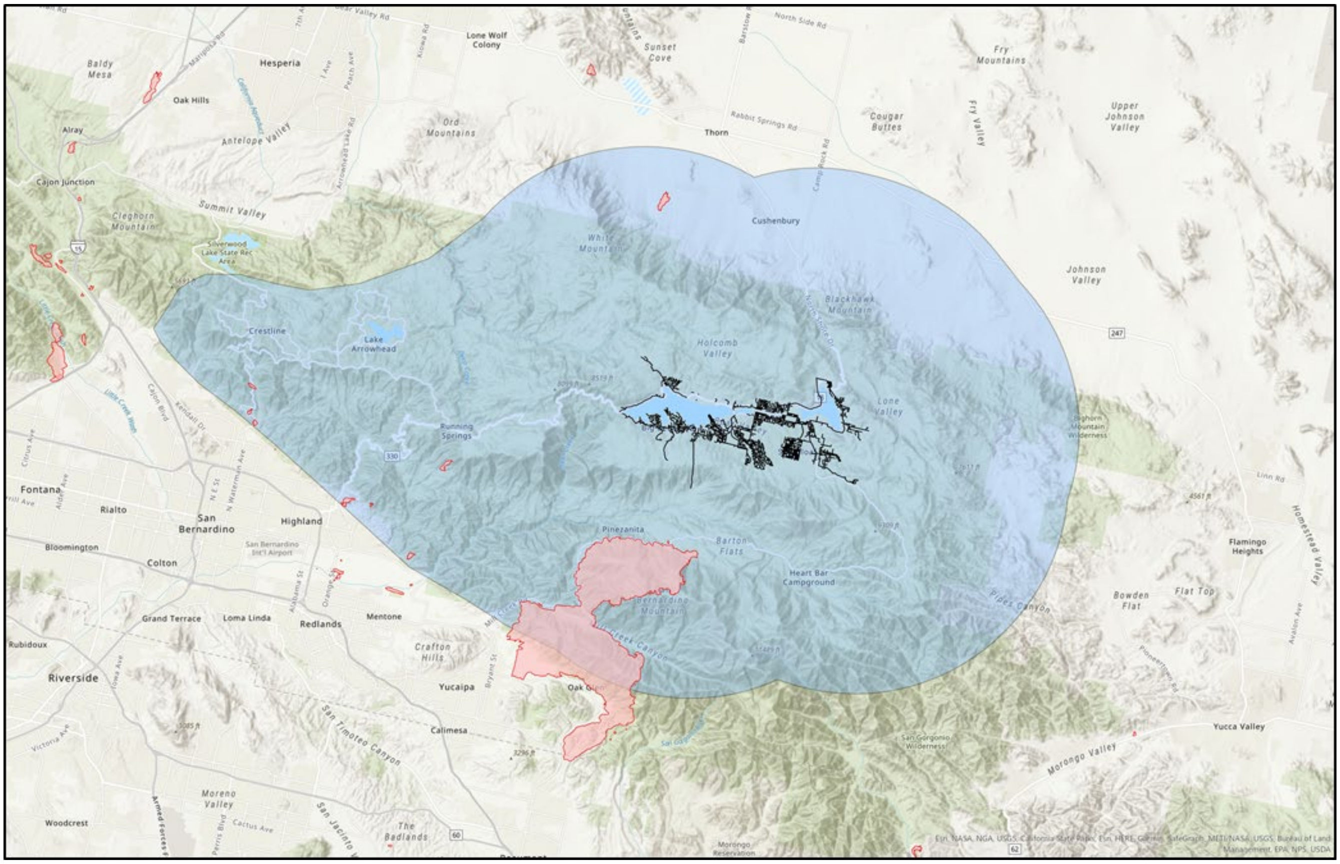
BVES does not have a separate infrared camera program. Infrared FLIR technology has been implemented in the AlertCalifornia HD camera system, which is described in the above section ALERT Wildfire Cameras (SAF_5).

Fire Growth Potential Software

In 2022, BVES began utilizing Technosylva's Wildfire Analyst Enterprise (WFA-E) wildfire forecasting application. This application includes FireCast and FireSim to simulate advanced fire spread and consequence modeling tools. BVES can run on-demand simulations at any points on a circuit to predict fire spread and consequence outputs such as fire perimeter size, structures impacted, and populations affected. This information assists in driving operational measures to mitigate wildfire including use of PSPS.

General Location of Detection Sensors: Figure 10-1, WFA-E Domain, illustrates the domain covered by the WFA-E model. It goes well beyond BVES's service area due to the potential for significant fire spread in the San Bernardino Mountains as a result of historical weather (winds, humidity), fuel levels, and topography.

Figure 10-2 WFA-E Domain



Resiliency of Sensor Communication Pathways: N/A- Technosylva simulation software does not use sensors.

Integration of Sensor Data into Machine Learning or AI Software: N/A- Technosylva simulation software does not use sensors.

Role of Sensor Data in Risk Response: N/A- Technosylva simulation software does not use sensors.

False Positives Filtering: N/A- Technosylva simulation software does not use sensors.

Time Between Detection and Confirmation: N/A- Technosylva simulation software does not detect ignitions.

Security Measures for Network-Based Sensors: N/A- Technosylva simulation software does not use sensors.

Table 10-4 Fire Detection Systems Currently Deployed

Detection System	Capabilities	Companion Technologies	Contribution to Fire Detection and Confirmation
HD Cameras (ALERTWildfire HD Cameras)	Continuous Monitoring During Hazardous Conditions 15 cameras in 7 Key Locations Across BVES service Territory	Technosylva – Fire Growth Potential Software	Visual Awareness in areas adjacent to electrical assets. Immediate fire alert
Fire Spread Modeling	BVES is utilizing Technosylva's FireCast and FireSim Applications to predict fire spread and consequence outputs such as fire perimeter size, structures impacted, and populations affected	N/A	Capability to forecast consequences that wildfire will have on a particular area
GreenGrid iSIU System	Physical Asset Condition, and Ignition Monitoring	N/A	Real-time monitoring of Radford, Boulder and North Shore circuits

10.4.2 Evaluation and Selection of New Detection Systems

Bear Valley evaluates the need for additional ignition detection systems as follows:

- Regarding expansion of its existing ignition detection systems, Bear Valley takes input from its primary users, Field Operations Staff.
- Bear Valley's management periodically reviews ignition detection programs and examines how systems can be improved as part of its continuous improvement process.
- If an expansion is contemplated, Bear Valley would assess the risk reduction benefit of the expansion. Currently, this would be done with the SMJU 7x7 Risk Based Decision Making Model.
- Regarding new systems, Bear Valley attends monthly WMP Joint IOU meetings and conferences and workshops that discuss wildfire mitigation. At these venues, Bear Valley is exposed to new systems. The new systems are reviewed by BVES management with user input as part of its continuous improvement process.
- If a new system is contemplated, Bear Valley will gather as much information on the system as possible, including alternatives to the system and user experiences with the system and then will make a risk based analysis on the benefit of the system. Currently, this would be done with the SMJU 7x7 Risk Based Decision Making Model.

10.4.3 Planned Integration of New Ignition Detection Technologies

Bear Valley currently does not plan to expand or implement new ignition detection systems. Bear Valley will continue to work with partners such as iSIU, Technosylva, UCSD, CAL FIRE, and Big Bear Fire Department to determine if additional cameras and sensors are warranted.

10.4.4 Evaluating Activities

BVES evaluates the efficacy of its fire detection systems as follows:

- Bear Valley takes input from its primary users, which are Field Operations Staff. This input is important to ensure the system is providing the user the required accuracy and information to support their activities and obligations.
- Bear Valley also reviews the reliability of the system by evaluating maintenance records, downtime, and performance.
- Bear Valley reviews automatic alerts and, if none occurs, periodically tests the alert communication path.

10.5 Weather Forecasting

Bear Valley has one initiative, Weather Forecasting (Tracking ID: SAF_6) in this section.

10.5.1 Existing Modeling Approach

Weather Forecasting (SAF_6)
BVES contracts with a meteorologist to provide detailed focused weather forecasts, at least weekly, tailored to Bear Valley's service area. The forecast report provides a 10-day forecast with the following information:

- Probability of precipitation
- Temperatures (Highs and Lows)
- Humidity (day and night)
- Rain estimate
- Snow estimate
- Winds (sustained wind speed and direction and gust speeds)
- Lightning activity level
- Flooding Risk
- Fire Risk (NFDRS)

The weather forecasts are used to evaluate the fire threat. Weather forecast details on the resources and datasets are as follows:

- Resources utilized for forecasting include a wide range of modeling data provided by NOAA, the National Weather Service, and the US Storm Prediction

Center. All numerical weather prediction data is considered and ingested from the National Center for Environmental Predictions (NCEP), Canadian Meteorological Center (CMC) and European Centre for Medium-Range Weather Forecasts (ECMWF), utilizing all deterministic and ensemble models, including, but not limited to HRRR and RAP for short range guidance, NAM and GEM-RDPS for medium-range, and ECMWF, GFS and VFSv2 for longer-range data. Ensemble models consist of SREF & GEFS. Another dataset taken into consideration is the Deterministic Model Forecasts of IVT, IWV, and TIVT provided by the Center for Western Weather Water Extremes, Scripps Institution of Oceanography at UC San Diego.
- Fire weather data, outlooks, and coordination are provided by the USFS along with the Southern California Geographic Coordination Center which includes hazardous outlooks from National Interagency Coordination Center and National Interagency Fire Center. All of the above data is considered when providing an accurate fire weather outlook and forecast for the San Bernardino Mountains and Big Bear Valley (BVES coverage area).

The meteorologist is able to obtain analysis of weather data before, during, and after certain extreme weather events. During elevated fire threat and storm conditions, the meteorologist provides forecasts at least daily. During a PSPS event, which BVES has not yet experienced, BVES's contracted meteorologist would provide near-continuous forecasting.

Bear Valley's use of WFA-E (Technosylva), while focused on risk and fire spread modeling, does incorporate a large array of weather stations including Bear Valley's 20 weather stations. The WFA-E model considers both current and forecasted conditions for the service area. The first step in running the WFA-E is in fact to update the weather forecast.

During the 2023-2025 WMP, Bear Valley was able to connect its 20 weather stations to the WFA-E model to improve the models risk analysis and forecast.

10.5.2 Known Limitations of Existing Approach

Weather models have temporal and spatial limitations to the parameters that are being modeled into the future. Additionally, it is often difficult to model the various microclimates that exist in the mountain communities. Often, forecasts assume homogenous terrain, but this is not the case. Technosylva's modeling outputs are greatly dependent on the quality of data provided by BVES and its weather assets, as well as the other weather stations from which it gathers data. Due to the topography and microclimates of BVES's service territory, it is possible that the weather data provided could be more granular. This granularity could yield a more accurate model output.

10.5.3 Planned Improvements

Bear Valley currently does not have planned changes or improvements in its weather forecasting. Technosylva does periodically update and upgrade its model.

10.5.4 Evaluating Activities

BVES evaluates the efficacy of its weather forecasting as follows:

- Bear Valley takes input from its primary users, which are Field Operations Staff. This input is important to ensure the system is providing the user the required accuracy and information to support their activities and obligations.
- Bear Valley also reviews the reliability of the forecasting by evaluating performance and downtime (non-availability).

10.5.5 Weather Station Maintenance and Calibration

BVES has developed a maintenance plan in which two (2) to three (3) weather stations undergo maintenance and calibrations per month. All weather stations must undergo maintenance at least once per year. This plan allows for timely maintenance activities while maximizing the number of operating weather stations. Sensors will be replaced as specified by the vendor. Records are maintained that include:

- The station name and location.
- The reason for the inability to conduct maintenance and/or calibration.
- The length of time since the last maintenance and calibration.
- The number of attempted but incomplete maintenance or calibration events for these stations in each calendar year.

Additionally, all the weather station's data is reviewed at least monthly. If a weather station is not operating properly, it will undergo non-scheduled corrective maintenance. When corrective maintenance is performed that could affect the calibration of the weather station, the weather station will have the annual maintenance and calibration performed on it prior to returning it to service.

Because Bear Valley's service area is small and the area where its facilities and weather stations are located is about 32 square miles, there is significant overlap between the 20 weather stations. Bear Valley believes that it can sustain 3 to 4 (20 percent) of weather stations being out of service at any given time. It should be noted that the Technosylva WFA-E model and Bear Valley's weather consultant utilize several other weather stations that are not owned and operated by Bear Valley. Therefore, there is more than sufficient coverage in the event 3 to 4 weather stations are out of service.

Currently, there are no limitations to performing annual maintenance on weather stations.

In the last calendar year (2024), there were no incomplete maintenance or calibration events for weather stations.

By performing annual maintenance and constantly reviewing weather station data and performance, Bear Valley is able to ensure acceptable levels of weather station coverage throughout the Bear Valley service territory. At the Bear Valley weekly management meeting, the number of out of service weather stations is briefed to management and actions being taken to restore service is discussed.

10.6 Fire Potential Index

Under the Fire Potential Index (SAF_7) initiative, Bear Valley implemented a Fire Potential Index (FPI) developed and customized to its service area by Technosylva. The FPI model is designed to quantify the potential for large or consequential wildfires several days out based on weather, fuels, and terrain inputs. The FPI model was implemented by Bear Valley in January 2024 and has been an integral factor in driving grid operational decisions in order to mitigate wildfire risk.

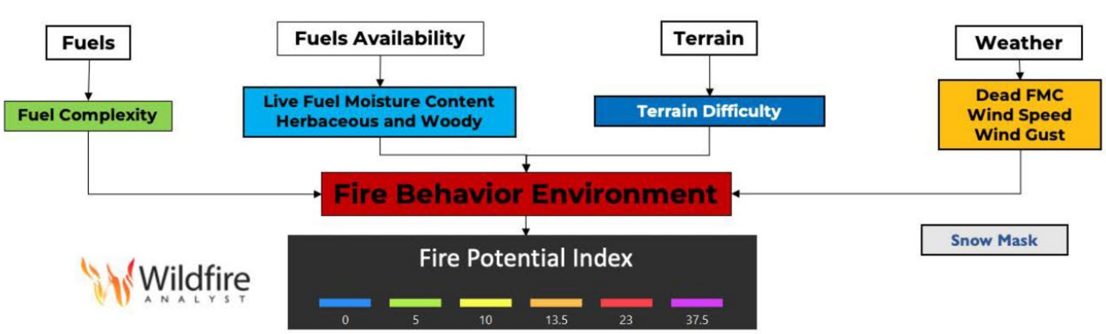
10.6.1 Existing Calculation Approach and Use

FPI quantifies the fire activity potential over the territory, aiming to assist operational decision-making to reduce fire threats and risks. FPI allows Bear Valley to analyze the short-term fire danger that could exist across the service territory and better communicate the wildfire potential on any given day and time, promoting safe and reliable operations.

Hexel-based (h3) FPI is a forecast product that is produced on a daily basis and calculated every 3 hours at different h3 resolutions from level 4 to 8 (approximately 182 ac and 1km resolution). One of the main advantages of this index is that it was calibrated with real fires (2012 to 2022) using VIIRS hotspots as a proxy of fire activity. FPI estimates the expected daily number of VIIRS hotspots in an h3-hexel level 6.

FPI comprises several variables, including fuels, terrain and weather as indicated in **Figure 10-3 Fire Potential Index Model Inputs**.

Figure 10-3 Fire Potential Index Model Inputs



Fire Potential Index includes weather data: wind speed, wind gusts, and both dead and live fuel moisture content. Technosylva's FPI also includes the Fuel Complexity (fuel structure, load and age) and Terrain Difficulty. These are key inputs of the classical fire triangle that explain fire behavior. Technosylva's Fire Potential Index (FPI) has been empirically trained and validated with real fire activity. The product is hexel-based (h3), allowing a better temporal and spatial analysis of outcomes, including the analysis by area. **Table 10-5. Fire Potential Features** provides FPI model features.

Table 10-5 Fire Potential Features

Feature Group	Feature	Altitude	Description	Source	Update Cadence	Spatial Granularity	Temporal Granularity
Fuels	Fuel Complexity	Surface	Fuel model complex is a measure of the fuel model loads and age present in the territory.	LANDFIRE enhanced with Technosylva proprietary fuels data	quarterly	30 m	N/A
Fuels	Live Fuel Moisture Content	Surface	Live Fuel Moisture Content - Herbaceous and Woody	Proprietary machine learning dataset created by Technosylva	annually	2 km	Daily
Terrain	Terrain Difficulty	Surface	Index to quantify difficulty in fire suppression efforts based on Accessibility, Penetrability, and Fireline Opening indexes	Technosylva proprietary index.	annually	30 m	N/A
Weather	Dead Fuel Moisture Content	Surface	Dead Fuel Moisture Content	WRF with Nelson Dead Fuel Moisture Model	daily	2 km	1 hr
Weather	Wind Speed	10 m	Hourly snapshot of the wind at 10 meters above ground level across the territory	WRF	daily	2 km	1 hr

Weather	Wind Gust	10 m	Sudden increase in wind speed. Technosyvla estimates wind gust magnitudes through a machine learning-based parameterization scheme.	WRF with Technosylva proprietary algorithm	daily	2 km	1 hr
Hotspots	Fire Activity	Surface	Satellite detected hotspot data from 2012 to 2022 was used to train ML algorithms to be used in real-time estimation of FPI.	VIIRS with Technosylva proprietary algorithm	On model update	hexel level 8 (0.78 mi)	3 hr

Technosylva has integrated FPI into its operational decision-making WFA enterprise to facilitate its use operationally. FPI promotes proactive and reactive operational measures through standard operating procedures aiming to reduce the likelihood that facilities and assets will be the source of ignition for a fire when FPI is high or extreme. FPI is used to inform operational decisions, as an input to PSPS decision-making, and to make risk-informed mitigation decisions. Bear Valley integrated FPI in its BVES Public Safety Power Shutoff Procedures, which is included in Appendix G. Some of the operational decisions where FPI is used to assist in the decision-making process include:

- Mode of operation for auto-reclosers and protective switches with Reclosing Capability mode of operation.
- Patrol requirements following circuit or feeder outages.
- Mode of operation for Fuse TripSavers.
- Designating circuit status (Consideration and In Scope for PSPS).
- Deploying Wildfire Risk Team(s).
- Use of any spark-producing tools and equipment.
- Conducting vegetation management work.
- Conducting “high risk” energized line work.
- Updating the latest list of medical baseline customers and impact on the Access and Functional Needs population.
- Reviewing Local Government, Agencies, First Responders, Critical Infrastructure, and Stakeholder notification lists and procedures.
- Reviewing customer notification procedures.
- Activating Emergency Operations Center (EOC).
- Initiating Local Government, Agencies, First Responders, Critical Infrastructure, and Stakeholder notification in accordance with BVES PSPS Procedures.
- Initiating customer notification in accordance with BVES PSPS Procedures.
- Preparing Bear Valley Power Plant for sustained operations.

- Conducting switching operations to minimize impact of potential PSPS activity.
- Activating first responders, local government and agencies, customers and the community, and stakeholders in accordance with the PSPS communications plan.

10.6.2 Known Limitations of Existing Approach

Bear Valley implemented its FPI model, developed by Technosylva, in January 2024 and has not had any updates to the existing approach or lessons learned since its roll out.

A key assumption to the FPI model is the accuracy of the input parameters. Technosylva reports the following limitations:

- Some fuel treatments are missing. Technosylva is closely working with CAL FIRE to monitor vegetation management with Calmmaper to include this in our fuel updates.
- Live Fuel Moisture Content (LFMC) varies by plant species. Technosylva considers the dominant and primary species in California. As a result, variations may occur at very local scales due to this factor.
- Technosylva utilizes satellite-measured NDVI. However, this approach does not allow for projections in our forecasts. To address this, we have developed a model that predicts NDVI based on weather conditions and other parameters. This data will be used to enhance the LFMC model.
- This index does not consider the location of fire stations which is related to the response time.
- Some fuel treatments are missing. Technosylva is closely working with CAL FIRE to monitor vegetation management with Calmmaper to include this in the TDI updates.
- The dead fuel moisture content model strongly correlates with the weather stations measuring 10h-FMC. However, Technosylva has identified that fuels in contact with the soil could have increased FMC compared to the sticks at 1 feet height above the ground. Technosylva corrects deadFMC based on soil moisture although more research is needed to further adjust this correction.
- Abrupt topography may cause local changes in both wind speed and direction due to wind turbulence.
- Abrupt topography may cause local changes in both wind speed and direction due to wind turbulence.
- The new FPI version will increase the index interpretation and its use for decision-making. It will include a composite index combining raw and percentile values.
- The new FPI will consider fire activity (number of hotspots) and rate of spread vectors to capture intense and fast fires. FPI 1.0 only used the fire activity to be trained. This will improve the model accuracy for grass fires.

The weather and fuels are forecasted parameters, which are inherently subject to inaccuracy. Additionally, these forecasted parameters are applied homogenously across each analysis are (hexagon). The terrain input is based on the “terrain difficulty index” which assumes homogeneous terrain type within each of the analysis areas.

10.6.3 Planned Improvements

As Bear Valley continues to gain experience with the FPI model, Bear Valley has the following two areas for planned improvements for FPI:

Integrate with Operational Decision Making: Bear Valley will continue to integrate FPI into its operational decision making and refine grid operational decisions based on FPI level. The intent is to develop standardized procedures that improve public safety based on FPI. At the end of year during the 2026-2028 WMP period, BVES will review its FPI operational decision making and make changes as applicable.

Improve Accuracy of Model as Feasible: Bear Valley will partner with Technosylva to explore reasonable methods to improve accuracy and resolution of the model. This effort will include better customizing the model to Bear Valley’s service area. Additionally, this effort will include correlating Bear Valley’s observation of actual conditions in the field with the FPI forecast and providing Technosylva on how the model performed. The intent is to improve model accuracy and reliability such that the decisions driven by FPI are properly focused to where actions must be taken to enhance public safety and to not unnecessarily reduce reliability. Each year Bear Valley will engage with Technosylva to explore ways to improve model accuracy and reliability. Additionally, at monthly meetings conducted between BVES and Technosylva, BVES will provide feedback on instances where the forecasted FPI as compared to what was observed in the field diverge.

11. Emergency Preparedness, Collaboration, and Community Outreach

11.1 Targets

11.1.1 Qualitative Targets

Table 11-1. Emergency Preparedness and Community Outreach Targets by Year below provides the targets for each initiative in the Emergency Preparedness, Collaboration, and Community Outreach category.

Table 11-1 Emergency Preparedness and Community Outreach Targets by Year

Initiative	Activity (Tracking ID #)	Previous Tracking ID, if applicable	2026 End of Year Total/Completion Date	2027 Status	2028 Status	Section; Page number
Emergency preparedness and recovery plan	Review and Update as needed PSPS and EDRP each year (Tracking ID: EP-1)	EP_1	100% Completed by December 31, 2026	100% Completed by December 31, 2027	100% Completed by December 31, 2028	11.2; p. 250
External collaboration and coordination	Conduct Stakeholder Briefs quarterly and Annual Tabletop Exercise (Tracking ID: EP_2)	EP_2	Annual Table Top Exercise completed by June 30, 2026 Stakeholder Briefs completed by August 31, 2026	Annual Table Top Exercise completed by June 30, 2027 Stakeholder Briefs completed by August 31, 2027	Annual Table Top Exercise completed by June 30, 2028 Stakeholder Briefs completed by August 31, 2028	11.3; p. 262

Public communication, outreach, and education	Achieve satisfactory outreach evaluation on semi-annual PSPS and wildfire customer survey. (Satisfactory is >60% overall.)(Tracking ID: EP_3)	EP_3	100% Completed by December 31, 2026	100% Completed by December 31, 2027	100% Completed by December 31, 2028	11.4; p. 268
Customer support in wildfire and PSPS emergencies	Review procedures for Customer support in wildfire and PSPS emergencies annually (Tracking ID: EP_4)	EP_5	100% Completed by December 31, 2026	100% Completed by December 31, 2027	100% Completed by December 31, 2028	11.5; p. 285

11.2 Emergency Preparedness and Recovery Plan

Bear Valley has one initiative, Emergency Preparedness and Recovery Plan (EP_1) for this activity.

This Section provides an overview of how Bear Valley has evaluated, developed, and integrated wildfire- and PSPS-specific emergency preparedness strategies, practices, policies, and procedures into its overall emergency plan based on the standards described in GO 166.

Bear Valley's approach to wildfire and PSPS emergency preparedness is to utilize the BVES Emergency Disaster Response Plan (EDRP) and the BVES PSPS Policy and Procedures plan to effectively and efficiently respond to a loss of power including a proactive de-energization (PSPS event) or wildfire event impacting the BVES service area. Bear Valley will utilize a PSPS to promote public safety as a measure of last resort by decreasing the risk of utility infrastructure as a source of wildfire ignitions. PSPS activation is consistent with the statutory obligation to protect public safety pursuant to Public Utilities Codes § 451 and 399.2(a).

Bear Valley's most recent Annual Report on Compliance with GO 166 was filed to the CPUC on April 30, 2024 and is available at the following link: BVES Annual Report on Compliance with GO 166.

The following is a list of relevant BVES documents that govern its wildfire and PSPS emergency preparedness planning for response and recovery efforts:

- Bear Valley Electric Service, Inc. Emergency & Disaster Response Plan, Revision 2, dated March 31, 2022 (provided in Appendix F)
- Bear Valley Electric Service, Inc. Public Safety Power Shutoff Plan, Revision 3, dated March 5, 2025 (provided in Appendix G)

11.2.1 Overview of Wildfire and PSPS Emergency Preparedness and Service Restoration

To prepare for a Wildfire or PSPS event, Bear Valley performs the following activities:

- Train staff on the BVES EDRP and the BVES PSPS Policy and Procedures Plan,
- Deploy wildfire response team(s) to high fire risk areas,
- Adjust protective device settings optimized for fire prevention (this is limited to adjusting the reclosing feature – automatic to manual), Increase frequency of consultant meteorologist forecast,
- Increase monitoring of Technosylva's WFA-E and running fire spread simulations,
- Increase monitoring of weather stations, forecasts, and fire threat conditions,
- Increase communications with SCE points of contact,

- Proactively engage with first responders, local government and agencies, and other stakeholders,
- Proactively communicate with customers and other stakeholders,
- Identify Medical Baseline customers and AFN populations that may be impacted,
- Prepare to activate Community Resource Center (CRC),
- Activation of Emergency Operations Center (EOC) and EDRP,
- Prepare Bear Valley Power Plant for sustained operations,
- Conduct switch operations to minimize impact of potential PSPS activity,
- Engage temporary generation, and
- Activate CRC,

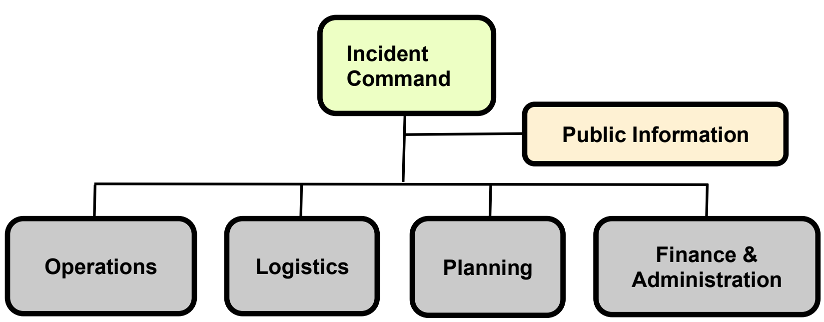
The EDRP requires that BVES's staff shall be organized largely based on the Standardized Emergency Management System (SEMS) as interpreted by the BVES. The SEMS structure utilized by BVES is a utility compatible Incident Command Structure (ICS) framework designed to manage emergency incidents and events.

SEMS is an emergency preparedness and response system endorsed by the State of California. It is the cornerstone of California's emergency response system and the fundamental structure for the response phase of emergency management. SEMS unifies all elements of California's emergency management community into a single integrated system and standardizes key elements. Additionally, it provides a common structure for all organizations responding to an emergency and a means of systematic planning. The benefits of using the SEMS include:

- Use of common terminology among agencies.
- Use of parallel organizational functions among agencies.
- Provides a standard means of systematic planning.

Figure 11-1 SEMS Organization show the basic SEMS organization structure that BVES utilizes in its EDRP.

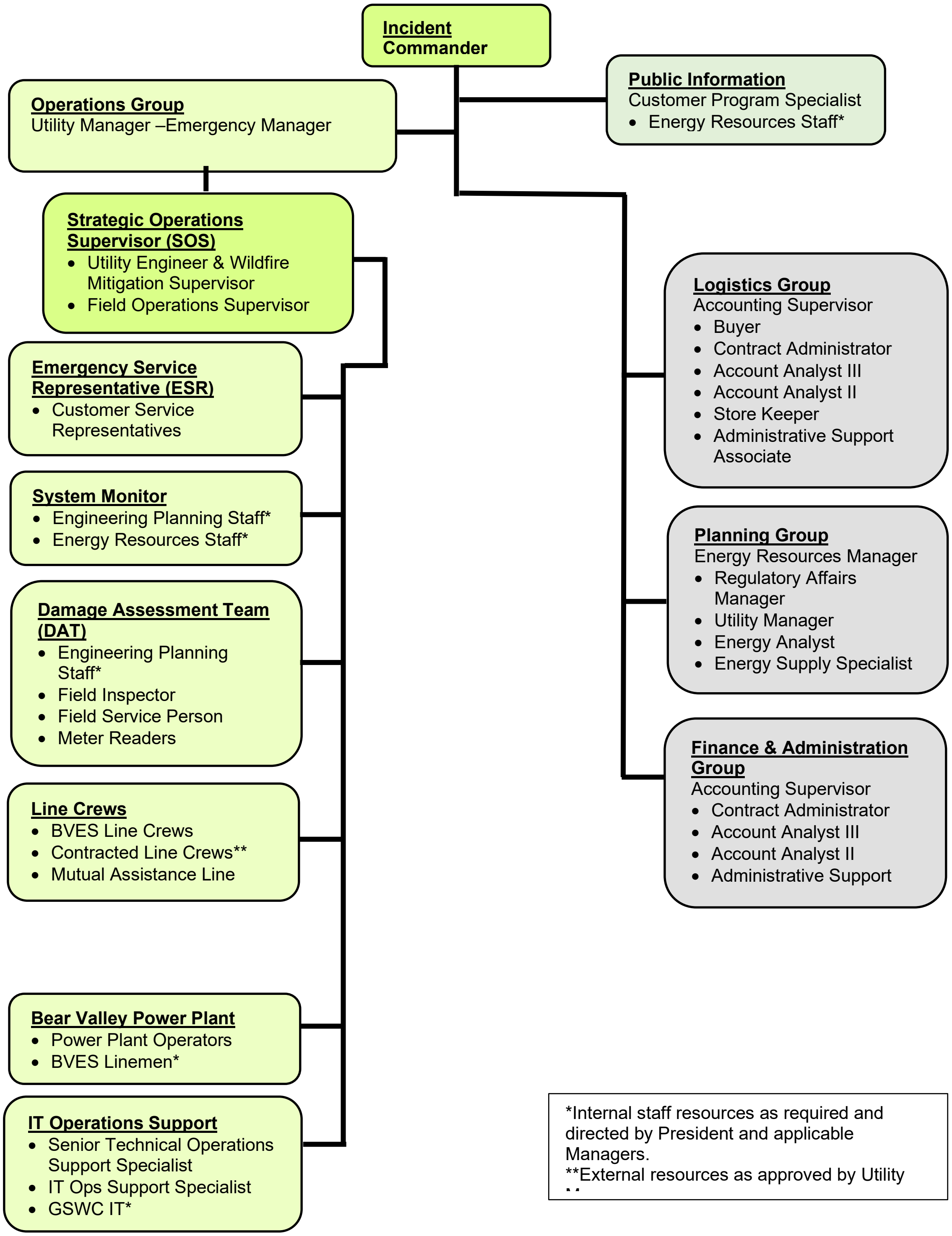
Figure 11-1 SEMS Organization



By organizing the response team along the SEMS structure, the BVES emergency response team coordinates with other government agencies via their corresponding groups. For example, BVES Operations coordinates directly with the City of Big Bear Lake EOC and San Bernardino County OES Operations Groups, as necessary. Additionally, when BVES sends a representative to these two centers, the representative brings a good understanding of the emergency response organization.

The organization chart presented on the next page in **Figure 11-2, BVES Emergency Organization**, provides the BVES Emergency Organization structure for the full mobilization (Level 1) of BVES's staff in responding to emergencies per this plan. This organizational structure is intended to operate out of an EOC established by BVES and be sustainable for long-term emergency response activities. Due to the size and available resources, the structure BVES utilizes for emergency and PSPS events are the same. Also, the personnel utilized in both Emergency and PSPS events are the same.

Figure 11-2 BVES Emergency Organization



The Emergency & Disaster Response Plan (EDRP) is provided to all Bear Valley Electric Service, Inc. ("BVES") employees to ensure an efficient, effective and uniform response during an emergency situation. BVES recognizes the importance of an integrated EDRP in order to safely provide for the energy needs of our customers and the requirements of our stakeholders in the event of an emergency.

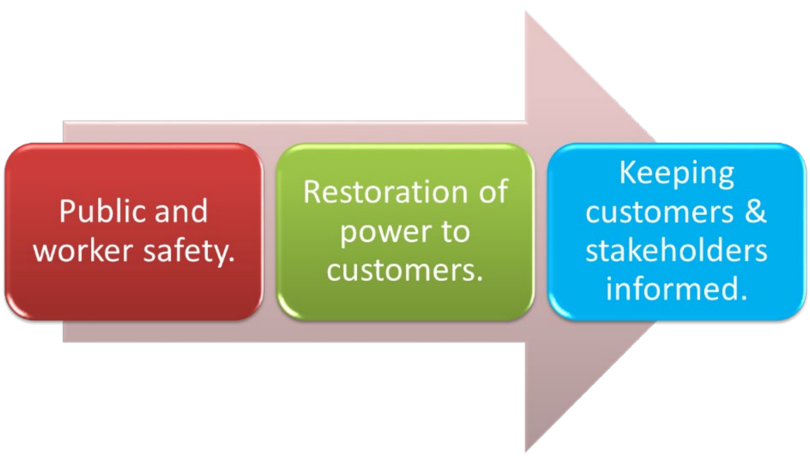
The EDRP outlines BVES' philosophy and procedures for managing major emergencies that may disrupt electric service to our customers or threaten the health and safety of the people in the communities we serve. The EDRP further establishes the structure, processes and protocols for the BVES's emergency response and identifies departments and individuals that are directly responsible for that response and critical support services. In addition, it provides a management structure for coordination and deployment of the essential resources necessary for the response.

The EDRP is designed to provide a framework for managing and responding to emergencies (outages, PSPS, loss of supplies, etc.) and disasters (earthquakes, flooding, synoptic weather event, wildfire, etc.). The EDRP may be invoked as a precautionary measure when there is a strong potential for outages or in response to actual outages.

When an emergency occurs, BVES's response actions are guided by the following overriding emergency goals (in order of priority) as indicated below and in **Figure 11-3, EDRP Goals**:

- **Safety:** Protect the life-safety of our customers, employees and the general public.
- **Restoration of Power:** Restore electric service to customers in a safe and timely manner.
- **Communications:** Keep customers, stakeholders, and staff informed.

Figure 11-3 EDRP Goals



BVES strives to utilize effective emergency management principles that enhance the BVES's ability to provide safe and reliable electric power and its ability to communicate timely and accurate information to customers and stakeholders by:

- Conducting effective risk assessments for operating and business functions;
- Developing appropriate prevention or risk mitigation strategies;
- Implementing comprehensive emergency preparedness programs;
- Responding with appropriate resources to address emergencies;
- Communicating with customers and other stakeholders with timely and accurate information;
- Recovering from events safely and expeditiously; and
- Improving continuously.

Since major outage events and emergencies are rarely similar in all respects, the EDRP is constructed in such a way to provide BVES management with a trained and operationally ready workforce and a response operations process that may be employed as required to deal with the unique aspects of each major outage and emergency event.

BVES customers receive electric service through an overhead and underground distribution system. Extreme weather events such as heavy rain, hail, snow, ice, lightning, high winds, and/or extreme dry heat may adversely impact the integrity of the distribution system, resulting in occasional interruptions of electric service. The distribution system is also susceptible to damages as a result of major disasters, such as earthquakes, flooding, wildfires, and mud and rock slides. Furthermore, in the interest of public safety, BVES may deem it necessary to proactively de-energize large portions of the distribution system to protect the public; for example, BVES may de-energize circuits or portions of circuits during extreme fire threat weather conditions. BVES normally imports power to its service area via Southern California Edison's (SCE) transmission lines. Therefore, the BVES service area may be susceptible to outages caused by events outside of its services area. All of the above may result in major power outages of varying extent and length depending on the severity of the event. Since electricity is a critical element in our daily lives, prompt restoration is a reasonable customer expectation and a BVES goal. In the case of major disasters, rapid and efficient restoration of power; especially to critical infrastructure, is essential to overall community disaster recovery.

The response to customer outages caused by severe weather events, other disasters or events affecting power delivery to the BVES service area is predicated on recognizing and understanding the magnitude of the event as well as the availability of resources to support the restoration process. This plan has been designed to provide a systematic organized response plan for the purpose of promoting a safe and efficient recovery from any of those conditions. Since the potential of sustaining damages is highest for storm situations, the plan specifically addresses these situations but it may easily be adapted to major outages caused by other disasters or causes.

It is also recognized that no plan can possibly predict and cover every emergency situation. Therefore, the EDRP provides a structure that is based on a set of reasonable assumptions for the most likely emergencies requiring emergency response; but it also provides the BVES's Incident Commander the authority, flexibility, and discretion to alter the BVES's emergency response to tailor it to the specific emergency situation in order to optimize the utilization of BVES resources and to achieve the emergency response goals in an effective and efficient manner.

A critical component of the EDRP is close coordination with stakeholders that depend on BVES's service and assistance for their response actions and who may, also, be able to assist BVES in its response actions. The coordination must occur in developing the plan, training on the plan, executing the plan, and in plan refinements. Some of BVES's major stakeholders include:

- Local officials (City of Big Bear Lake (CBBL) and San Bernardino County)
- State officials (California Public Utilities Commission)
- San Bernardino County Office of Emergency Services (County OES)
- Big Bear Fire Department
- California Department of Forestry and Fire Protection (CAL FIRE)
- U.S. Forest Service
- San Bernardino County Sheriff's Department Big Bear Lake Patrol Station
- California Highway Patrol (CHP) Arrowhead Area
- California Department of Transportation (Caltrans)
- Big Bear Area Regional Wastewater Agency (BBARWA)
- Big Bear City Community Services District (CSD)
- Big Bear Lake Water Department (DWP)
- Big Bear Municipal Water District (MWD)
- Southwest Gas Corporation
- Bear Valley Community Hospital
- Bear Valley Unified School District
- Big Bear Chamber of Commerce
- Big Bear Airport District
- Big Bear Mountain Resort
- Various media and communications companies

Accurate, effective and timely communications with key stakeholders is critical in emergency response and, therefore, it is essential that business relationships be developed before emergency response is necessary. Understanding stakeholders' key staff, contact information, roles and responsibilities, and capabilities are extremely useful in achieving successful emergency response.

There are three basic emergency response levels that BVES uses. Level 1 and 2 pertain to the EDRP and Level 3 refers the normal BVES working hours and afterhours Field Operations and Customer Service outage response procedures and processes. When the EDRP is activated, Level 1 or 2 are used to describe level of EOC activation and restoration response process. Level 3 is the normal Service Crew (or Dutyman for afterhours) response process to outages and system problems during the course of normal Transmission & Distribution operations. The response levels to outages and emergencies are summarized in **Figure 11-4. BVES Outage and Emergency Response Levels** below:

Figure 11-3 BVES Outage and Emergency Response Levels

Response	Event Type	Action	Comments
Level 1	High Risk Long-term*	EOC fully activated EDRP processes implemented	It is preferred to fully activate EOC and then shift to Level 2 activation, if full response determined to not be necessary.
Level 2	Moderate Risk Short-term	EOC partially activated EDRP processes implemented	Level of EOC activation and EDRP implementation as directed by Utility Manager.
Level 3	Low Risk Short-term	Normal Service Crew/Dutyman and Customer Service processes	These events are normally within the capability of assigned Service Crew or Dutyman to resolve with the normal on call resources.

*Long-term is generally defined as 12 hours.

In the event of a wildfire, the following are flow charts for EDRP and PSPS events:

Figure 11-4 EDRP Event Flowchart

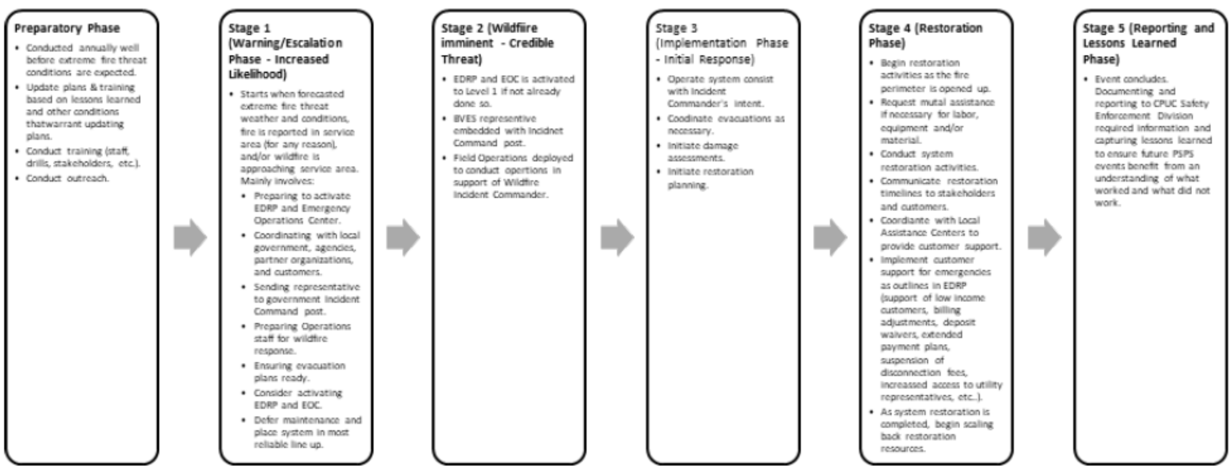
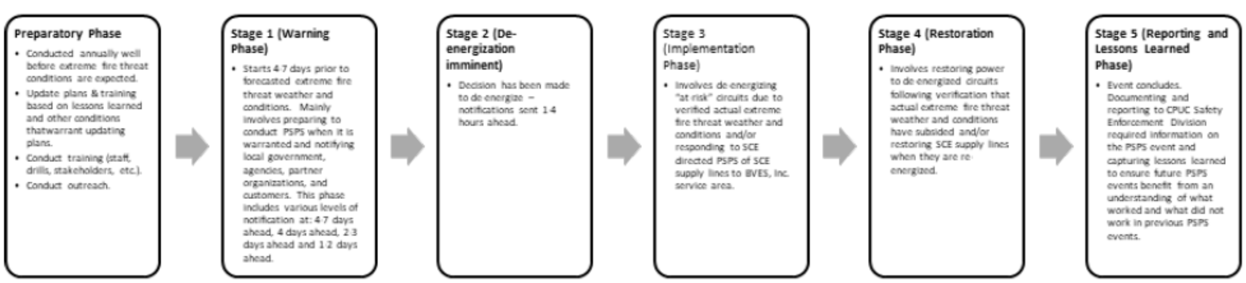


Figure 11-5 PSPS Event Flowchart



For PSPS training, BVES performs two drills per year one table top drill and one full scale exercise), which includes the public, stakeholders, CPUC, and OEIS involvement. One of the PSPS training is a table-top exercise and the other is a full-scale exercise. BVES also conducts at a minimum, two internal training sessions for PSPS.

For Emergency response, BVES conducts a minimum of one internal training session annually. BVES reviews the EDRP annually utilizing the FEMA National Planning System 6-Step Process. BVES also staffs up its EOC at least once per year (real world event or, if none, then for training (drill scenario)). If an emergency or PSPS event takes place, BVES will review its performance and develop lessons learned. Training will be conducted to the appropriate personnel for lessons learned.

BVES assigns personnel for each task which matches their expertise. Examples are: the Incident Commander is the President, the Emergency Manager is the Utility Manager, and the Finance and Administration Group is led by the Accounting Supervisor.

Possible resources in addition to BVES resources include CUEA mutual assistance and Big Bear Valley Mountain Mutual Aid Association.

- California Utilities Emergency Association (CUEA). The Incident Commander shall determine if gapped resources are best provided by utilizing the CUEA Mutual Aid Agreement, which allows member utilities to request and obtain labor, materials, and/or equipment resources from other member utilities in a rapid manner on a reimbursable basis.
- Big Bear Valley Mountain Mutual Aid Association ("MMAA"). While MMAA does not have power line construction and repair resources, they do have access to significant support resources including traffic controls, road clearing services, coordination with local government agencies, other utilities, and other nongovernmental organizations, and communications with the public. Additionally, one of the most significant strengths of MMAA is its ability to coordinate through its member organizations support and relief for customers experiencing extended sustained major power outages. This may include health and welfare checks, shelters, meals, cooling centers, restroom and shower stations, etc.

Table 11-2. Key Gaps and Limitations in Integrating Wildfire- and PSPS-Specific Strategies into Emergency Plan provides gaps and limitations in integrating Wildfire- and PSPS-specific strategies in the EDRP.

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
Bear Valley has never invoked a PSPS so its direct experience is non-existent.	Continue to work with other IOUs to gain knowledge and best practices from their direct experiences.	**Strategy:** Participate in AFN Council and Joint IOU WMP sessions. Also, review other IOU PSPS reports and attend workshops on PSPS when offered. **Target timeline:** This is ongoing and Bear Valley should target all of these activities each year.

Limited coordination with Local Government and Agencies	Work with Local Government and Agencies to gain their input to Bear Valley's EDRP and PSPS.	**Strategy:** Conduct a workshop for EDRP and PSPS with Local Government and Agencies and provide an opportunity for them to edit the EDRP and PSPS. Provide final copies of these documents to Local Government and Agencies. **Target timeline:** Conduct coordination strategy for PSPS in 2026 and conduct coordination strategy for EDRP in 2027.

11.2.2 Planning and Allocation of Resources

The EDRP provides guidance on planning and resources. The Incident Commander must assess the following:

- Resources necessary to execute the restoration activities in a safe, effective and efficient manner;
- Available resources in the Service Area;
- Gaps in resource availability to execute the restoration activities in a safe, effective and efficient manner; and
- When resources from outside entities such as CUEA mutual aid and/or contracted resources may be released.

Based on the above assessments, the Incident Commander shall coordinate with the Logistics Group leader to request additional resources as necessary to fill resource gaps and to relinquish resources when no longer required. Possible resources in addition to BVES resources include CUEA mutual assistance, contracted services and Big Bear Valley Mountain Mutual Aid Association.

Emergency Response preparations are a long-term process for which each BVES Department must be constantly ready. Preparations for emergency response are best achieved through training on the EDRP, continuous evaluation of the plan, coordination and outreach with external stakeholders, provisioning emergency response materials and equipment, and establishing mechanisms to rapidly bring emergency response resources to the service area such as mutual aid agreements, contracts, and other partnering agreements.

The EDRP has an Emergency Response Preparations Checklist, which is designed to assist Managers and Supervisors in short-term emergency response preparations. The checklist is ideally triggered at the 96-hour point prior to a potential emergency response event such as a major forecasted winter storm. However, staff must be flexible and understand not all emergency response events will be accurately forecasted; hence, the implementation time of this checklist may be significantly less than 96-hours. In the event that major outages occur without warning, it is still useful to go through the Emergency

Response Preparations Checklist and complete the preparatory checklist items as applicable.

The checklist is designed to be all-inclusive of plausible emergency response to storm events for the BVES service area such as winter snowstorms. Therefore, certain preparatory items may not be applicable for all emergency response events; for example, vehicle snow chains may not be required during a loss of import power supply lines from Southern California Edison (SCE). The Utility Manager may direct certain items on the checklist need not be executed as applicable. Additionally, the Utility Manager may direct new preparatory items be added to the checklist depending on specific impending conditions. The Utility Manager shall use this checklist as applicable when extreme fire threat weather that could result in PSPS conditions is forecasted. The Utility Manager shall keep the President informed of any changes to the checklist.

Obtaining material and equipment is always a challenge given that the BVES service area is remotely located and at approximately 7,000 feet in mountainous terrain with only three points of access. The roads present a significant challenge to large trucks under most conditions and all vehicles in wintery ice and snow conditions. Therefore, it is essential to the success of BVES' emergency response plan that certain minimum levels of materials and equipment be always readily available in the BVES service area.

The PSPS Procedures also provide preparatory guidance as follows:

- **Preparatory (pre-fire season):**
  - Managers review and update plans and procedures.
  - Managers ensure staff are trained on PSPS procedures as applicable.
  - Reach out to media and community-based organizations to ensure consistent awareness of and availability to third parties of all messaging and map data, including application programming interfaces that are used for de-energization events.
  - Customer Service Department will ensure all equipment and supplies for the CRC are functional and readily available.
  - Coordinate with stakeholders including CPUC, CalFire, CalOES, communications providers, representatives of people/communities with access and functional needs, and other public safety partners to plan de-energization simulation exercises throughout the utility service territories in the areas with the highest historical and forecasted risk for de-energization in advance of fire season.
- **Warning (4-7 Days Ahead of fire threat weather):**
  - Evaluate system for possible impact area(s) and ensure resources ready to support PSPS.
  - Contact SCE Staff and closely follow status of SCE supply lines (Doble, Cushenberry, and Bear Valley/Radford).
  - Review operational and maintenance status of sub-transmission system.
  - Review operational and maintenance status of Bear Valley Power Plant (BVPP).
  - Review operational and maintenance status of Radford Line.
  - Consider conducting patrol of Radford Line.

- Review FPI, WFA-E, National Weather Service (NWS) forecasts, National Fire Danger Rating System (NFDRS) 7-day forecast, and weather and threat assessments from contracted meteorology consultant.
- Notify meteorology consultant to provide more frequent forecasts.
- Alert customer service to possibility of PSPS.
- Review and edit as applicable templates for PSPS events and the anticipated impacts on BVES Customers.
- Staff drafts notices to Public Affairs consultant for review, significant changes to templates are made.
- Create warning notifications to customers via email, telephone calls, IVR proactive calling system, and two-way text messaging.

- **Warning (2-3 Days Ahead of fire threat weather):**
  - Continue to closely monitor fire weather alerts.
  - Prepare staff rotation plans to support continuous field crew operations, BVPP operations, dispatch, and customer service.
  - Evaluate need for additional resources from mutual aid agreements (CUEA and MMAA) and contracted services. Alert additional resources points of contact.
  - Set up processes to frequently monitor BVES-installed weather stations.
  - Review pre-approved field Switching Orders against current system line-up and make changes as applicable with Field Operations Supervisor’s approval.
  - Keep Customer Service informed of latest forecast to ensure accurate communications with stakeholders.
  - Closely coordinate with SCE Staff regarding SCE supply lines to the BVES service area.
  - Finalize “2-3-Day Notice” regarding forecasted extreme fire threat weather and conditions, about possible BVES directed PSPS and/or SCE directed PSPS.
    - Provide anticipated impacts on BVES Customers and direction of event.
    - Obtain President’s approval to release.
  - Issue a press release to local media (newspaper and radio) and post notification on website.
  - Create warning notifications to customers via email, telephone calls, (IVR) proactive calling system, and two-way text messaging.
- **Warning (1-2 Days Ahead of fire threat weather):**
  - Continue to closely monitor fire weather alerts and observed conditions from various sources with the goal of refining the forecast.
  - If needed, request additional resources from mutual aid agreements (CUEA and MMAA) and contracted services).
  - Keep Customer Service informed of latest forecast to ensure accurate communications with stakeholders.
    - Set up CRC and conduct a mock SOE scenario to include testing of all equipment and needed supplies.
    - Purchase non-perishable food items to provide to our customers including bottled water.
  - Continue to closely coordinate with SCE Staff regarding SCE supply lines to the BVES service area.
  - When directed by the Utility Manager:

- Staff incident responders called in.
- Incident dispatch established.
- Field Crews dispatched to monitor various actual field conditions for extreme fire weather and other dangerous conditions throughout the service area and "at risk" areas.
- Implement BVES EDRP including staffing the EOC as applicable.

- Finalize **"1-2 Day Notice"** regarding imminent extreme fire threat weather and conditions, which may result in BVES directed PSPS and/or SCE directed PSPS.
  - Provide anticipated impacts on BVES Customers and duration of event.
  - Obtain President's approval to release.
- Identify medical baseline and AFN customers that may lose power as result of PSPS.
- Issue a press release to local media (newspaper and radio) and post notification on website.
- Issue warning notifications to customers via email, telephone calls, (IVR) proactive calling system, and two-way text messaging

11.3 External Collaboration and Coordination

11.3.1 Communication Strategy with Public Safety Partners

Communication Policies, Practices, and Procedures

BVES has implemented a structured, multimodal emergency communication framework to ensure timely, accurate, and complete coordination with public safety partners, emergency response agencies, and interconnected electrical corporations before, during, and after wildfire, PSPS, and re-energization events. This strategy is aligned with General Order (GO) 166 and PUC Section 768.6 to support situational awareness, operational readiness, and rapid emergency response efforts.

BVES tailors its communication protocols to meet the specific operational needs of fire departments, law enforcement agencies, emergency operations centers (OES), municipal governments, regulatory agencies (CPUC & Energy Safety), and other interconnected utilities. Recognizing that each public safety partner maintains unique notification requirements, communication platforms, and response structures, BVES coordinates directly with each entity to ensure seamless integration of emergency communications and response strategies.

To facilitate effective and standardized coordination with state, county, and municipal emergency agencies, first responders, and interconnected utilities, BVES follows formalized policies and procedures, including:

BVES Table 11-1 Communication Approaches

Pre-Event Coordination & Planning	Real-Time Communication During Wildfires & PSPS Events	Post-Event Information Sharing & Debriefs
• **Annual drills with fire departments, law enforcement agencies, emergency operations centers (OES), and regulatory agencies to assess notification effectiveness and response coordination (See Section 6.1, PSPS Plan Appendix G).** • **Pre-established emergency notification lists that include direct points of contact for first responders, CPUC, Energy Safety, and mutual aid partners.** • **Routine data-sharing agreements with interconnected utilities to facilitate grid status monitoring and re-energization planning (See Section 7, PSPS Plan Appendix G).** • Formalized PSPS notification procedures that outline escalation triggers, notification timing, and alert formats for public safety agencies (See Section 6.3, PSPS Plan Appendix G).	• **Emergency Alerts** o Priority alerting via multiple platforms (radio, SMS, email, and secured government networks) o Interoperable communication channels to ensure seamless coordination between BVES and first responders o Hourly updates to emergency responders on grid status and estimated restoration timelines • **Interoperable Communication Systems** o Direct PSPS impact notifications sent to fire agencies, OES, and law enforcement. o Interagency communication channels established to ensure alignment across first responders and emergency response teams. o Hourly operational briefings to CPUC, Energy Safety, and government agencies regarding PSPS status, estimated restoration timelines, and grid stability conditions (See Section 6.3, PSPS Plan Appendix G) • **Mutual Aid & Utility Coordination** o Notifications issued to neighboring utilities to ensure regional grid coordination during PSPS activations o Data-sharing with state agencies to facilitate public safety operations and resource deployment	• Regulatory compliance reporting to CPUC and Energy Safety regarding PSPS execution, stakeholder notifications, and lessons learned (See Section 7, PSPS Plan Appendix G) • Stakeholder engagement meetings with first responders, law enforcement, and emergency agencies to assess notification effectiveness and refine emergency response coordination • After-action reviews (AARs) conducted with public safety agencies and regulatory bodies to identify opportunities for improving situational awareness and emergency messaging procedures • Public safety coordination workshops to review best practices, communication barriers, and procedural enhancements for future emergency activations

Table 11-3 High-Level Communication Protocols, Procedures, and Systems with Public Safety Partners

Public Safety Partner Group	Name of Entity	Key Protocols	Frequency of Prearranged Communication Review and Update
Fire	Local County Fire Department	• Communication capabilities (staffing, resources, technologies) • Methods for information exchange • Backup systems & data management strategy • Common alerting protocols & messaging • Predefined emergency contacts (See BVES Emergency Plan)	Annually (around April – May)

Law Enforcement	County Sheriff's Office	• Real-time emergency alerts & PSPS activation notifications • Coordination on public safety response • Information sharing through secured channels (See Section X, Emergency Plan)	Annually (around April – May)
Office of Emergency Services	County & State OES Agencies	• Multi-agency coordination & data-sharing • Situational reports on wildfire threats & grid stability • PSPS debrief meetings (See Section Y, Emergency Plan)	Quarterly
Regulatory & Government	CPUC & Energy Safety	• PSPS notifications & compliance reporting • Emergency operations monitoring • Performance evaluation of emergency communication protocols (See Section Z, Emergency Plan)	As needed
Interconnected Electrical Corporations	Neighboring Utility Companies	• Mutual aid coordination • Load balancing & resource-sharing agreements • PSPS grid impact assessments (See Section A, Emergency Plan)	Annually and during potential events

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
Limited feedback on wildfire & PSPS emergency plan	Less than 10% of state & local government stakeholders have participated in emergency plan review.	**Strategy**: Host a 1.5-day workshop with state & local agencies to review emergency preparedness strategies. Solicit verbal & written comments from stakeholders. Assign liaison for follow-up engagement. **Target Timeline:** By end of 2026

Inconsistent notification receipt across agencies	More than 50% of government partners have independent & non-standardized communication systems.	**Strategy**: Develop a multi-channel alert system that includes text, email, & secondary confirmation methods. Conduct a survey of public safety partners to align notification preferences with BVES's capabilities. **Target Timeline:** By end of 2027.

11.3.2 Collaboration on Local and Regional Wildfire Mitigation Planning

BVES understands the importance of collaborating with local government and agencies including county, city, and tribal agencies on wildfire mitigation. There are no tribal groups in the BVES service area. The key jurisdictions in the BVES service area are the City of Big Bear Lake, County of San Bernardino, Caltrans and the US Forest Service. BVES maintains strong working relationships with Additionally, City of Big Bear Lake, County of San Bernardino, Caltrans, US Forest Service, Big Bear Fire Department, San Bernardino Fire Department, CHP Arrowhead, San Bernardino County Sheriff's Department Big Bear Lake Patrol Station, Big Bear City Community Services Department and other local groups.

BVES attends the Big Bear Valley Mountain Mutual Aid Association (MMAA) meetings, held five times per year, and at each meeting discusses wildfire mitigation planning efforts. MMAA membership includes: City of Big Bear Lake, Big Bear Fire Department, San Bernardino County Fire, San Bernardino County Department of Public Health, San Bernardino County Office of Emergency Services (OES), San Bernardino County Sheriff's Department, San Bernardino County Transportation Authority, San Bernardino County Emergency Communications Service (ECS), US Forest Service, California Highway Patrol, California Department of Transportation, Big Bear Airport, Big Bear City Community Services District, Big Bear Lake Department of Water & Power, Big Bear Lake Municipal Water District, Big Bear Area Regional Water Authority, Southwest Gas, Bear Valley Community Healthcare District, Bear Valley Unified School District, Mountain Area Regional Transit Authority, Bear Mountain Ski Resorts, Big Bear Chamber of Commerce, Big Bear Lake Resort Association, Big Bear Valley Recreation & Park District, American Red Cross, Big Bear Community Emergency Response Team (CERT), Big Bear Valley Community Organizations Active in Disaster (COAD), Big Bear Valley Voluntary Organizations Active in Disaster (VOAD), Civil Air Patrol, and Salvation Army.

Periodic meetings and recurring communication between BVES and local government and agencies strengthen the likelihood of demonstrating resiliency during emergencies. Due to the small service area, BVES can effectively engage local government and agencies frequently and prioritizes these engagements due to the significant impact that they have in achieving community buy-in.

Table 11-5. Collaboration in Local Wildfire Mitigation Planning provides listing of local wildfire mitigation planning efforts.

Table 11-5 Collaboration in Local 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
San Bernardino County Third District Supervisor	WMP and PSPS	Meeting with County Supervisor Rowe	Conducted virtual meeting on at 10:30 am January 21, 2025
Big Bear Mountain Mutual Aid Association (MMAA)	WMP and PSPS	Group presentation with Q&A	Briefed MMAA at 9:00 am on February 11, 2025
Utility Wildfire General Order Scope Discussion	WMP	IOU and PU Coordination Meeting	Virtual Brief December 13, 2024
BVES PSPS Working and Planning Group, Stakeholder Meeting	PSPS	Briefing to Local Stakeholders	Virtual Brief December 12, 2024
Inland Empire Fire Safe Alliance Meeting	WMP	Meeting with Fire Fighting Agencies, USFS, other local community stakeholders	Virtual Brief November 13, 2024
PSPS Working Group Meeting + Microgrid Workshop - Central Region - AND- Inland Empire & Northern Region	PSPS	Meeting Utilities & Local Government & Agencies	Virtual Brief November 7, 2024
Statewide Access and Functional Needs/Joint IOU Meeting	PSPS	Meeting	Roundtable discussion September 17, 2024
Collaborative Council / Joint access functional needs	PSPS	Meeting	Virtual meeting September 9, 2024
BVES and Big Bear Fire Department Coordination Meeting	WMP	Meeting`	Coordination and upcoming projects discussion on July 29, 2024

CUEA Annual Conference	WMP and PSPS	Conference	Conference briefs on May 10, 2024
CMUA Annual Wildfire Mitigation Plan Roundtable	WMP and PSPS	Conference	Conference briefs on December 6, 2023

Table 11-6 Key Gaps and Limitations in Collaborating on Local Wildfire Mitigation Planning provides listing of gaps and limitations in collaborating on local wildfire mitigation planning.

Table 11-6 Key Gaps and Limitations in Collaborating on Local Wildfire Mitigation Planning

Subject of Gap or Limitation	Brief Description of Gap or Limitation	Strategy for Improvement
Limited coordination with Local Government and Agencies	Work with Local Government and Agencies to gain their input to Bear Valley's WMP Initiative.	**Strategy:** Conduct a workshop for WMP Initiatives with Local Government and Agencies and provide an opportunity for them to review proposed initiatives. **Target timeline:** Conduct coordination workshop for WMP Initiatives in 2026 and conduct WMP Initiative review in 2027.

11.3.3 Collaboration with Tribal Governments

There are no tribal lands in Bear Valley’s service area. Therefore, there is no information for **Table 11-7. Collaboration with Tribal Agencies** and **Table 11-8. Key Gaps and Limitations in Collaborating with Tribal Agencies.**

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
None	N/A	N/A	N/A

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
None	N/A	N/A

11.4 Public Communication, Outreach, and Education Awareness

Comprehensive Communication Strategy

BVES implements a multimodal communication strategy—providing timely and complete messaging regarding wildfires, wildfire-related outages, PSPS events, and service restoration in accordance with PUC Section 768.6. BVES's approach integrates emergency communication protocols, public messaging, and public awareness while addressing gaps and limitations.

Emergency Communication Protocols & Messaging Strategy

BVES follows structured communication protocols to provide real-time, accessible notifications before, during, and after wildfire events and PSPS activations (See Section 6.1, PSPS Plan Appendix G).

BVES Table 11-2 BVES Communication Protocols

Communication Protocol	Description & PSPS Plan Reference
Pre-Approved Templates	Consistent messages across channels (See Table 6-1, PSPS Plan Appendix G)
Multimodal Outreach	Alerts via TV, radio, print media, website updates, social media, phone calls, SMS, IVR, and emergency coordination meetings (Section 6.3 PSPS Plan Appendix G)
Targeted Notifications	Prioritized alerts for essential services, AFN populations, Tribal Nations, and remote-area residents (See Section 6.3, PSPS Plan Appendix G)
Verification & Adaptation	Stakeholder feedback and post-event analysis ensure continuous improvement (See Section 7, PSPS Plan Appendix G)

BVES provides clear, action-oriented messaging tailored to diverse stakeholder needs.

BVES Table 11-3 BVES Messaging Strategy Table

Messaging Category	Description & PSPS Plan Reference
Preparedness Alerts (4-7 Days Ahead)	Initial public notifications for wildfire risks and potential PSPS events (See Table 5-1, PSPS Plan Appendix G)
Emergency Updates (During Event)	Hourly updates via automated alerts, website, and social media (See Section 6.3, PSPS Plan Appendix G)
Service Restoration Notices (After Event)	Final restoration updates, resource availability, and safety guidance (See Section 7, PSPS Plan Appendix G)
Accessibility	Multilingual translations, alternative text formats, and AFN accommodations (See Section 6.3, PSPS Plan Appendix G)

Outreach & Awareness Strategy

BVES provides ongoing education initiatives to enhance public preparedness captured below.

BVES Table 11-4 Outreach & Education Awareness Programs

Wildfire, PSPS, and Service Restoration Awareness	Post-Event Debrief Sessions (PEDS) & Continuous Improvement	Vegetation Management Education & Risk Mitigation
• Annual training on wildfire preparedness and PSPS (See Section 6.1, **PSPS Plan Appendix G**) • Public education via social media, mailers, emergency agencies • Radio, TV, digital, and local agency coordination (See Section 6.3, **PSPS Plan Appendix G)**	• Surveys from customers and emergency agencies (See Section 7, PSPS Plan Appendix G) • Structured PEDS with agencies, first responders, and Tribal reps (See Section 7, PSPS Plan Appendix G)	• Education on defensible space and fire risk reduction (See Section 6.3, PSPS Plan Appendix G) • Coordination with fire departments and forestry agencies (See Section 6.1, PSPS Plan Appendix G) • Direct engagement with property owners in high-risk areas (See Section 6.3, PSPS Plan Appendix G)

Current Gaps & Limitations

Key areas for enhancement cover expanding real-time translation capabilities by improving automated multilingual messaging, improving rural communication methods with radio alerts and satellite notifications, and enhancing message verification mechanisms to track message receipt and effectiveness, ensuring accurate communications (See Section 7, PSPS Plan Appendix G).

11.4.1 Protocols for Emergency Communications

Protocols for Emergency Communications

BVES follows structured communication protocols to notify stakeholders before, during, and after wildfires, wildfire-related outages, and PSPS events. These protocols align with requirements, best practices, and stakeholder insights for timely and complete messaging.

BVES Table 11-5 BVES Stakeholder Outreach Table

Stakeholder Group	Outreach Method
General Public (Section 6.3, PSPS Plan Appendix G)	Regional alerts via TV, radio, newspapers, website updates, and social media
Priority Essential Services (Section 6.3 PSPS Plan Appendix G)	Direct notifications (contact lists, dedicated call lines, and emergency calls)
AFN Populations (See Section 6.3, PSPS Plan Appendix G)	Text-to-speech alerts, large-font notifications, personalized calls for medical baseline customers, and coordination with disability advocacy groups

Limited English Proficiency (See Section 6.3, PSPS Plan Appendix G)	Translated messages via automated calls, SMS, IVR, website updates, and multilingual call center support
Tribal Nations (See Section 6.1, PSPS Plan Appendix G)	Direct engagement with Tribal leaders, if any, and emergency coordinators
Remote Residents (Section 6.3, PSPS Plan Appendix G)	Radio notices, direct mailers, & in-person alerts from emergency crews

Notification Protocols for Wildfires, Outages, and PSPS Events

The table includes multimodal communication strategies for timely and accessible notifications.

BVES Table 11-6 BVES Stakeholder Outreach Methods

Before Events (Preparedness & Early Alerts)	During Events (Real-Time Emergency Messaging)	After Events (Service Restoration & Lessons Learned)
• **4-7 days ahead issuing public alerts** • **Phone calls, SMS texts, and IVR notifications (Section 6.3, PSPS Plan Appendix G)** • **Social media, website updates, and outage maps (Section 6.3 PSPS Plan Appendix G)** • **Local TV, radio stations, and print media (See Section 6.3, PSPS Plan Appendix G)** • **Coordination with local emergency, tribal leaders, if any, and CBOs**	• Hourly updates via automated alerts, website, & social media • Check-ins with critical infrastructure and AFN to confirm message receipt • Adjust messaging based on real-time fire/weather conditions (Section 7, PSPS Plan Appendix G)	• Notifications for restoration timelines and safety measures • Follow-up communication with AFN customers and emergency responders • Post-event debriefs and data analysis to refine future outreach (See Section 7, PSPS Plan Appendix G)

During PSPS exercise, BVES describes each communication area and considers stakeholder feedback, which has led to the strategy presented above. Each communication channel is updated, when applicable, before and post-simulations to enhance effectiveness as BVES has not recorded a wildfire nor PSPS event within its service territory (See Section 7, PSPS Plan Appendix G).

Decision-Making Process for Issuing Notifications

Staff adhere to the following decision-making process:

- Situation Assessment – BVES monitors conditions through weather forecasting tools and grid status, coordinating emergency alerts with CAL FIRE and local responders
- Notification Triggers – Messaging initiated based on fire risk levels, grid stability, and safety concerns; alerts issued at least 4-7 days in advance, with continuous updates
- Improvement – BVES uses message verification tools, stakeholder insights, and annual debriefs to assess and improve communication strategies (See Section 7, PSPS Plan Appendix G)

Best Practices: Ensuring Timely, Accurate, & Complete Communications

BVES uses standardized, action-oriented messaging templates (See Table 6-1, P PSPS Plan Appendix G), multilingual and accessible notifications, direct collaboration with public safety partners, Tribal representatives, and local agencies, and continuous improvement via post-event reviews and stakeholder feedback (See Section 7, PSPS Plan Appendix G). A more detailed summary of stakeholder communication protocols and concerns is presented in Table 11-9 of the PSPS Plan Appendix G.

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
General Public	Wildfire	TV, radio, newspapers, website updates, and social media (See Section 6.3, PSPS Plan Appendix G)	Customer response tracking, outage website analytics, media monitoring	Real-time outage updates, restoration estimates, safety guidance
General Public	Wildfire-related outage	Automated alerts via phone, SMS, IVR, email (See Section 6.3, PSPS Plan Appendix G)	Customer response tracking, outage website analytics, media monitoring	Real-time outage updates, restoration estimates, safety guidance
General Public	PSPS-related outage	Hourly messaging via automated alerts and social media (See Section 6.3, PSPS Plan Appendix G)	Customer response tracking, outage website analytics, media monitoring	Real-time outage updates, restoration estimates, safety guidance
General Public	Restoration of service	Notifications for restoration timelines via automated alerts (See Section 6.3, PSPS Plan Appendix G)	Customer response tracking, outage website analytics, media monitoring	Timely updates on service restoration, customer support access

Priority Essential Services	Wildfire	Direct outreach to service providers, priority notification list, dedicated call lines (See Section 6.3, PSPS Plan Appendix G)	Response confirmation from critical infrastructure facilities, status reports	Advance warning for power disruptions, continuity planning, emergency backup needs
Priority Essential Services	Wildfire-related outage	Response confirmation from critical infrastructure facilities, status reports (See Section 6.4, PSPS Plan Appendix G)	Response confirmation from critical infrastructure facilities, status reports	Advance warning for power disruptions, continuity planning, emergency backup needs
Priority Essential Services	PSPS-related outage	Direct communication via emergency coordination meetings, priority call lines (See Section 6.4, PSPS Plan Appendix G)	Response confirmation from critical infrastructure facilities, status reports	Advance warning for power disruptions, continuity planning, emergency backup needs
Priority Essential Services	Restoration of service	Dedicated restoration updates through direct outreach and emergency contacts (See Section 6.4, PSPS Plan Appendix G)	Response confirmation from critical infrastructure facilities, status reports	Timely restoration of service for critical operations

AFN Populations	All event types	Text-to-speech messages, large-font alerts, coordination with disability advocacy groups (See Section 6.3, PSPS Plan Appendix G)	Follow-up calls, coordination with AFN service providers, CRC check-ins	Ensuring accessibility of messages, timely assistance, medical equipment support
Populations with Limited English Proficiency	All event types	Translated messages in multiple languages, multilingual call center support (See Section 6.3, PSPS Plan Appendix G)	Community feedback channels, multilingual helpline logs	Availability of translated materials, culturally appropriate outreach
People in Remote Areas	All event types	Radio-based notifications, in-person alerts from local emergency teams (See Section 6.3, PSPS Plan Appendix G)	Local emergency teams confirm receipt through direct interaction	Reliable communication in areas with low connectivity, emergency preparedness support

11.4.2 Messaging

Procedures for Developing Effective Messaging

BVES has crafted a structured, multimodal communication strategy to ensure that the largest percentage of stakeholders within its service area receive clear, timely, and action-oriented accessible messaging before, during, and after a wildfire, wildfire-related outage, or PSPS event. This strategy is outlined in Section 6 of BVES's PSPS Plan Appendix G and integrates with the Emergency Disaster and Response Plan (EDRP) to create a coordinated, transparent communication approach. The following references sections within the 2025 PSPS Plan Appendix G .

BVES's messaging strategy is continuously improved with the following principles in mind:

- Incorporate standardized, pre-approved messaging templates for targeted notices, which helps spread clear and consistent messages; (See Table 6-1, PSPS Plan Appendix G)
- Dispersal of information through multimodal outreach via email, phone calls, two-way text messaged, IVR, social media, website notices, public radio and press releases, and local media outlets; (See Section 6.3, PSPS Plan Appendix G)
- Collaboration with local government agencies, Public Safety Partners, and CBOs to amplify messaging reach; (Section 6.1)
- Timely notifications are issued in phases: 4-7 days, 2-3 days, 1-2 days, 1-4 hours ahead, and during/post-event updates (See Table 5-1).

Overview of the Development of BVES's Communication Messaging Strategy
In addition to the procedures above, BVES compiled the following table with an overview of the development of the following communication messaging components. See BVES Table 11-7 below.

BVES Table 11-7 Messaging Communication Strategy

Messaging Component	Development Strategy
Features to Maximize Accessibility	Taking insights from socialized lessons, community member feedback, and industry best practices, BVES developed its accessibility measures in accordance with CPUC SED and Energy Safety requirements. This incorporates high-contrast visuals, large fonts, and screen-reader compatibility. BVES also integrated alternative communication formats for AFN customers and provides in-person assistance if and when a CRC is stood up (See PSPS Plan Appendix G Appendix C).
Alert and Notification Schedules	BVES's notification schedule evolved through internal operational testing and simulation run-throughs while maintaining accordance with requirements. The current timeline balances early warning needs with the development of accurate real-time updates. Each notification phase aligns with emergency preparedness best practices (See PSPS Plan Appendix G Section 6.2).

Translation of Notifications	BVES developed its translation process in response to community demographic requirements of major languages spoken regionally. Initially relying on automated translations, BVES now uses human verification processes to ensure clarity and accuracy. Languages covered are based on customer preference data collected through account registrations (See PSPS Plan Appendix G Section 6.3).
Messaging Tone and Language	The development of BVES's messaging tone was guided by crisis communication principles and customer feedback from past PSPS events. Changes incorporated refinements for concise and clear messaging that is action-oriented with different tones for pre-event preparedness, in-event safety updates, and post-event restoration guidance (See Section 6.1).
Key Components and Order of Messaging	The standard messaging structure (hazard description, impacted areas, timing, safety actions, restoration process) was developed through internal after-action reviews of past PSPS events. This order ensures that customers receive the most critical information first. Adjustments were made based on feedback from public safety partners and Table 6-1 provides the structured templates BVES follows.

11.4.3 Outreach and Education Awareness Activities

Outreach and Education Awareness Programs

Overview of Outreach and Education Awareness Programs

BVES implements a comprehensive outreach and education awareness strategy that aims to provide insights to key stakeholders and the public surrounding wildfire threats, potentials, seasonal forecasts, potential for PSPS activation, service restoration practices, and vegetation management practices. BVES's public outreach initiatives focus on proactive education, risk communication, and emergency preparedness, which emphasizes role understanding before, during, and after emergencies. These efforts are executed through multi-channel engagement, partnerships, and direct outreach to vulnerable communities.

BVES Table 11-8 Key Outreach & Education Initiatives

Outreach & Education Initiative	Description & PSPS Plan Appendix G Reference
Public Safety & Wildfire Awareness Campaigns	Educational materials via social media, direct mail, local news outlets, and community events (See Section 6.3, PSPS Plan Appendix G)
PSPS Readiness Webinars	Live and recorded training sessions for residents and businesses in high fire-risk areas on PSPS procedures (See Section 6.1, PSPS Plan Appendix G)
Vegetation Management Education	Defensible space guidelines and property owner outreach in wildfire-prone areas (See Section 6.3, PSPS Plan Appendix G)
Emergency Response Partnership Training	Joint exercises with first responders and emergency coordinators to enhance situational readiness (See Section 6.1, PSPS Plan Appendix G)
AFN Assistance & Community Support	Specialized outreach for customers with medical baseline needs and those requiring accessible notifications (See Section 6.3, PSPS Plan Appendix G)
Tribal Engagement & Emergency Planning	Collaboration with Tribal representatives, emergency coordinators, and local agencies (See Section 6.1, PSPS Plan Appendix G)
Remote Area Emergency Communication Pilot	Expansion of satellite-based messaging and radio alerts for rural communities (See Section 6.3, PSPS Plan Appendix G)

Implementation Approach—Staff & Resources

BVES's outreach and education programs are led by a specialized team consisting of communication coordinators, emergency preparedness specialists, and community outreach partners who collaborate to deliver timely, accessible, and effective messaging before, during, and after wildfire and PSPS events. To ensure comprehensive public engagement and responsiveness to emergency conditions, BVES strategically allocates resources as follows:

- Trained Facilitators & Industry Experts lead PSPS preparedness exercises, simulations, and community webinars, equipping residents, businesses, and essential service providers with the information needed for emergency planning. Staff receive annual training in risk communication, emergency notification protocols, and outreach strategies for vulnerable populations (See Section 6.1, PSPS Plan Appendix G).
- Customer Service & Communication Teams develop multilingual messaging, public information campaigns, and social media outreach, ensuring content is accessible across multiple platforms, including radio, TV, printed materials, and digital channels (See Section 6.3, PSPS Plan Appendix G).
- Dedicated AFN Support Staff developed personalized outreach to customers enrolled in the medical baseline program and AFN groups, offering assistive technologies, plain-language alerts, and customized notifications for individuals with disabilities and other access and functional needs (See BVES AFN Plan, Section 4.2).
- Emergency Response Coordination with local governments, first responders, and emergency response agencies to align public safety messaging and conduct joint training exercises, scenario-based simulations, and after-action reviews (See Section 7, PSPS Plan Appendix G).
- Scalable Staffing & Emergency Activation during high-risk wildfire conditions or PSPS activations, allowing BVES to expand its public communication response team by activating on-call outreach specialists and leveraging partnerships with local emergency agencies and mutual aid groups for real-time communication efforts.
- BVES's outreach and education programs are supported by a dedicated team who work collaboratively to ensure effective communication with all stakeholders. The team includes communication coordinators, emergency preparedness liaisons, and community outreach partners, each playing a critical role in delivering timely, accurate, and accessible information before, during, and after wildfire and PSPS events. To maximize outreach effectiveness, BVES allocates resources strategically to ensure comprehensive public engagement:
- Trained facilitators and industry experts lead PSPS preparedness simulations and exercises, support community webinars and meetings, and support BVES internal staff to equip residents, businesses, and critical service providers with the necessary information to plan for potential outages;

- Marketing and Communication Teams develop multilingual messaging, social media campaigns, and public information materials, ensuring key messages reach diverse audiences across multiple platforms;
- Dedicated AFN Support Staff provide personalized outreach to customers enrolled in the medical baseline program, offering assistive technologies and ensuring accessible notifications for individuals with disabilities and other access and functional needs (See BVES AFN Plan, Section 4.2); and
- Collaboration with Emergency Response Agencies strengthens coordination with local first responders, fire departments, and government agencies, ensuring that BVES's public safety messaging aligns with state and local emergency preparedness guidelines (See Section 6.1, PSPS Plan Appendix G).

Implementation Methods

BVES follows industry best practices in risk communication and emergency preparedness to ensure its outreach programs are effective, accessible, and continuously improving. Outreach methods are designed to meet the specific needs of diverse populations and to promote preparedness and response through a multi-channel engagement strategy.

BVES employs a data-driven approach to communication, ensuring that its outreach efforts are clear, action-oriented, and accessible to all stakeholders. By leveraging behavioral risk communication research, social marketing principles, and studies on public response to emergencies, BVES refines its messaging to enhance comprehension and engagement. Public safety notifications are disseminated through multiple communication channels, including digital platforms (social media, website updates, and email alerts), traditional media (radio, TV, and newspapers), direct mail, in-person events, and emergency alert systems to maximize reach and effectiveness (See Section 6.3, PSPS Plan Appendix G). This multi-platform strategy ensures that key messages are delivered promptly and in formats suitable for diverse communities, including those with AFN populations.

To further strengthen its outreach, BVES collaborates with local governments, first responders, CBOs and advocacy groups to develop culturally relevant and locally appropriate communication strategies (See Section 6.1, PSPS Plan Appendix G). These partnerships enhance the effectiveness of emergency messaging by ensuring that at-risk populations receive tailored support and guidance. Additionally, BVES conducts annual PSPS Readiness Exercises, simulating wildfire and outage scenarios to evaluate and refine public notification protocols and stakeholder engagement strategies (See Section 7, PSPS Plan Appendix G). These simulations allow BVES to test messaging effectiveness, identify communication gaps, and improve coordination with emergency response agencies, reinforcing its commitment to continuous improvement and public safety.

Long-Term Monitoring & Evaluation

BVES is committed to continually assessing and improving its outreach and education programs to ensure that messaging remains effective, inclusive, and responsive to community needs. Several mechanisms are used to evaluate the success of communication efforts and identify areas for improvement:

- After each PSPS activation, wildfire preparedness session, and stakeholder meeting, BVES collects community feedback to assess how well messages were received and understood (See Section 7, PSPS Plan Appendix G);
- BVES tracks attendance rates at PSPS webinars, wildfire education sessions, and vegetation management consultations to measure community involvement and identify gaps in outreach;
- Following emergency events and simulated PSPS exercises, BVES conducts after-action reviews to evaluate the effectiveness of response efforts and refine communication strategies accordingly (See Section 7, PSPS Plan Appendix G); and
- BVES holds post-event discussions with local governments, AFN communities, Tribal representatives, and emergency response agencies to gather qualitative insights on communication effectiveness and identify unmet needs (See BVES AFN Plan, Section 4.5).

These evaluation efforts ensure that BVES remains proactive in improving its outreach strategy—adapting communication methods based on real-world feedback, emerging industry best practices, and lessons learned from past PSPS activations. By continuously refining these processes, BVES strengthens its commitment to public safety, preparedness, and transparent communication.

Identified Gaps & Areas for Improvement

While BVES's outreach programs effectively serve most stakeholders, opportunities for enhancement include expanding automated multilingual messaging capabilities, improving radio-based alerts and satellite notifications for remote and underserved communities and refining systems for message receipt confirmation (See Section 7, PSPS Plan Appendix G).

Table 11-10 List of Target Communities

Target Community	Interests or Concerns Before, During, and After Wildfire and PSPS events
Populations with Limited English Proficiency	Limited access to wildfire risk information, need for multilingual emergency alerts, culturally appropriate outreach, and assistance in understanding PSPS notifications (See Section 6.3, PSPS Plan Appendix G).
People in Remote Areas	Challenges with internet connectivity, reliance on radio-based alerts, and limited access to Community Resource Centers (CRCs) during PSPS activations (See Section 6.3, PSPS Plan Appendix G).

Elderly Residents	Concerns about mobility limitations, access to emergency transportation, medical device power needs, and difficulty receiving real-time alerts (See Section 6.3, PSPS Plan Appendix G).
People with Limited Technology Access	Barriers to receiving digital alerts and emergency notifications, reliance on landline calls, printed notices, and in-person community support (See Section 6.3, PSPS Plan Appendix G).
AFN Populations (People with Disabilities, Medical Needs, or Other Functional Limitations)	Require personalized notifications, early warning for power-dependent medical devices, access to backup power resources, and targeted outreach through support organizations (See Section 6.3, PSPS Plan Appendix G).
Essential Service Providers (Hospitals, Fire Departments, Water Systems, etc.)	Require early warning for PSPS events, direct coordination with BVES emergency teams, and access to power continuity planning resources (See Section 6.3, PSPS Plan Appendix G).

11.4.4 Engagement with Access and Functional Needs Populations

Engagement with AFN Populations

BVES recognizes the critical importance of ensuring that Access and Functional Needs (AFN) populations receive tailored support and communication during wildfire events, outages, and PSPS activations. To enhance preparedness, accessibility, and response efforts, BVES continuously evaluates, designs, and implements policies, programs, and strategies specific to AFN customers throughout its service territory. The BVES AFN Plan provides comprehensive details on AFN risk initiative strategies, emergency preparedness protocols, stakeholder engagement efforts, and targeted outreach methods to ensure timely, accurate, and accessible communication. The BVES AFN Plan can be found here: https://www.bvesinc.com/assets/documents/psps/r.18-12-005_bves-afn-plan-2025-final.pdf.

AFN Demographics & Distribution

BVES serves a diverse customer base, including AFN populations who may experience heightened risks during wildfire and PSPS events. AFN customers include individuals with disabilities, older adults, individuals with limited English proficiency, medically vulnerable populations, and those with mobility or communication challenges.

BVES Table 11-9 Summary of AFN Customers in BVES Territory

AFN Category	Percentage of Total Customer Base	Distribution Trends

Medical Baseline Customers	0.62% of total customers	Concentrated in high-risk wildfire zones and remote areas
Individuals with Disabilities	BVES starting tracking these detailed AFN metrics on December 19, 2024	Primarily in residential neighborhoods and AFN communities
Seniors (Ages 65+)	BVES starting tracking these detailed AFN metrics on December 19, 2024	Widely distributed but higher concentrations in rural areas
Populations with Limited English Proficiency (LEP)	BVES starting tracking these detailed AFN metrics on December 19, 2024	Primarily Spanish-speaking and Tagalog-speaking populations
Low-Income & Transportation-Challenged Residents	BVES starting tracking these detailed AFN metrics on December 19, 2024	Higher reliance on community-based support and in-person outreach

(See BVES AFN Plan, Section 3.1 for detailed AFN customer demographic data and geographic distribution trends.)

Challenges & Needs of AFN Populations During Wildfires & PSPS Events

AFN populations experience heightened vulnerabilities before, during, and after wildfire or PSPS incidents due to medical dependencies, mobility constraints, communication barriers, and evacuation challenges. BVES actively works to identify these critical risk factors through customer engagement, stakeholder partnerships, and data analysis.

BVES Table 11-10 Key Challenges Identified for AFN Customers

Challenge	Implications During Wildfires & PSPS Events
Medical Equipment Dependency	Loss of power disrupts life-sustaining medical devices (e.g., ventilators, CPAP machines, refrigeration for medications).
Limited Mobility & Transportation Access	Challenges with evacuations, CRC access, and emergency transport assistance during fire threats and outages.
Communication Barriers	AFN customers require alternative notification formats, text-to-speech options, and ASL interpretation for emergency alerts.
Language Access Limitations	Customers with Limited English Proficiency (LEP) require translated notifications and in-language support services.
Digital Divide & Technology Gaps	Many low-income and older adult residents lack internet or smartphone access, requiring phone-based and in-person outreach.
Evacuation & Shelter Accessibility	Limited availability of ADA-compliant evacuation centers and shelters with AFN accommodations.

(See BVES AFN Plan, Section 4.1 for a full assessment of AFN challenges and risks.)

BVES Strategies to Address AFN-Specific Needs

To mitigate risks and enhance resilience for AFN populations, BVES has implemented several AFN-specific programs and policies designed to ensure proactive outreach, accessible communication, and real-time support.

BVES Table 11-11 High-Level Strategies & Policies for AFN Support

Strategy / Policy	Key Features & Implementation Details
AFN Customer Notification Enhancements	• Customized alerts via text-to-speech, large print, and ASL video translations • Automated multilingual messaging for Limited English Proficiency (LEP) communities (See Section 6.3, PSPS Plan Appendix G)
Medical Baseline Support & Resilience Resources	• Proactive outreach to all medical baseline customers before fire season (See BVES AFN Plan, Section 4.2) • Coordination with local agencies and healthcare providers to distribute battery backups and emergency preparedness kits
Community Resource Center (CRC) Accessibility Improvements	• Expanded CRC locations to include AFN-compliant evacuation centers • On-site accessibility accommodations (e.g., wheelchair access, sign language interpreters, and assistive listening devices)
AFN-Specific Evacuation & Emergency Transport Plans	• Collaboration with county paratransit services and non-profit partners to provide transportation assistance for AFN customers during PSPS activations • Emergency transportation partnerships to ensure AFN residents can access shelters safely
CBO & Tribal Collaboration on AFN Preparedness	• Partnerships with CBOs, disability advocacy organizations, and Tribal governments to enhance outreach. • Annual meetings to improve emergency response planning for AFN communities
Post-Event AFN Impact Assessments & Recovery Support	• Targeted surveys and focus groups to gather AFN feedback on PSPS event response effectiveness • Post-event debriefs with AFN advocacy organizations to refine strategies

(See BVES AFN Plan, Section 5.2 for more details on AFN risk mitigation strategies and program implementation.)

Ongoing AFN Engagement & Feedback Mechanisms

BVES prioritizes direct engagement with AFN customers to continually assess program effectiveness and identify evolving needs. BVES ensures that AFN stakeholders have direct input in shaping emergency response strategies through the following ongoing feedback mechanisms:

- Meetings with disability advocates, senior groups, healthcare partners, and CBOs to evaluate outreach effectiveness (See BVES AFN Plan, Section 5.3);
- Collection of feedback from AFN customers after PSPS events and emergency drills to improve communication strategies (See Section 7, PSPS Plan Appendix G); and
- Meetings and workshops with Tribal representatives, AFN community leaders, and first responders to incorporate direct feedback into BVES planning efforts.

11.4.5 Engagement with Tribal Nations

There are no tribal lands in Bear Valley's service area.

11.4.6 Current Gaps and Limitations

The table below describes the key gaps and limitations identified in BVES's public emergency communication strategy.

Table 11-11 Key Gaps and Limitations in Public Emergency Communication Strategy

Gap or Limitation Subject	Brief Description of Gap or Limitation	Remedial Action Plan
Limited feedback on wildfire & PSPS emergency plan	Less than 10% of state & local government stakeholders have been able to provide feedback on emergency preparedness planning	Strategy: Host a 1.5-day workshop with state & local agencies to review emergency preparedness strategies. Solicit verbal & written comments from stakeholders. Assign liaison for follow-up engagement. (See Section 7, PSPS Plan Appendix G) Target Timeline: By end of 2026

Low participation from AFN communities in outreach programs	Many AFN residents are unaware of BVES wildfire & PSPS preparedness programs due to outreach gaps in language access & accessibility limitations	Strategy: Expand multilingual messaging & alternative formats (e.g., large print, ASL videos, braille). Strengthen AFN partnerships with CBOs & advocacy groups. Conduct targeted outreach via CRCs & AFN service networks. (See BVES AFN Plan, Section 5.2) **Target Timeline:** By end of 2026
Inefficiencies in real-time emergency alert delivery	Some customers report delays in receiving emergency alerts via SMS, IVR, & automated calls during PSPS events, especially in low-signal rural areas	Strategy: Upgrade mass notification system to enhance alert speed & reliability. Implement radio-based emergency notifications for remote areas. Conduct PSPS notification performance testing & system audits. (See Section 6.3, PSPS Plan Appendix G) Target Timeline: By end of 2027
Limited awareness of vegetation management efforts	Many customers do not understand how vegetation management reduces wildfire risk, leading to public concerns about tree-trimming activities	Strategy: Launch a Vegetation Management Awareness Campaign through social media, direct mail, & community meetings. Enhance transparency in vegetation clearing schedules & create a public GIS mapping tool showing planned tree-trimming areas. (See Section 6.3, PSPS Plan Appendix G) Target Timeline: By end of 2027

Barriers to outreach in remote communities	Remote-area residents face connectivity challenges & rely heavily on radio, in-person outreach, & satellite-based messaging	Strategy: Expand satellite-based emergency alerts & establish mobile outreach teams for door-to-door notifications in high-risk rural areas. Partner with local radio stations to provide real-time PSPS updates & safety messaging. (See Section 6.3, PSPS Plan Appendix G) Target Timeline: By end of 2027
Populations with Limited English Proficiency	All event types	Translated messages in multiple languages, multilingual call center support (See Section 6.3, PSPS Plan) **Target Timeline:** By end of 2028
People in Remote Areas	All event types	Radio-based notifications, in-person alerts from local emergency teams (See Section 6.3, PSPS Plan) **Target Timeline:** By end of 2028

11.5 Customer Support in Wildfire and PSPS Emergencies

Customer Support in Wildfire and PSPS Emergencies

BVES is committed to ensuring that customers receive the necessary support and resources before, during, and after wildfire emergencies and PSPS events. BVES has developed customer-focused programs, financial assistance options, and emergency response protocols to mitigate disruptions and assist both residential and non-residential customers during emergencies. BVES's customer support programs align with requirements and incorporate best practices to ensure accessibility, financial relief, and rapid response to customer concerns.

BVES Table 11-12 Customer Emergency Services Overview

Emergency Service	Description & BVES Plan Reference
Outage Reporting	Customers can report outages 24/7 through the BVES website, automated phone system, and customer service hotline. Real-time outage maps provide status updates (See Section 6.3, PSPS Plan Appendix G)
Support for Low-Income Customers	Income-qualified customers can enroll in discounted rate programs and financial assistance for PSPS-related hardships (See BVES CARE & FERA Program Guidelines)
Billing Adjustments	Customers affected by wildfires or extended PSPS events may qualify for bill credits or temporary adjustments
Deposit Waivers	New or transferring customers affected by wildfire-related displacement may receive deposit waivers for new BVES accounts
Extended Payment Plans	Customers experiencing financial hardship due to wildfire or PSPS may request longer repayment terms with flexible options
Suspension of Disconnection & Nonpayment Fees	Disconnection for nonpayment is suspended during declared emergencies and PSPS activations. Late fees are waived for qualifying customers (See BVES Emergency Assistance Policy)
Repair Processing & Timing	BVES prioritizes rapid service restoration for wildfire-damaged infrastructure and ensures streamlined repair processing for affected customers
Community Assistance Locations & Services	BVES operates its CRC with charging stations, water, and real-time emergency updates (See Section 6.1, PSPS Plan Appendix G)
Medical Baseline Support Services	Medical Baseline customers receive priority notifications, backup power resources, and direct assistance before PSPS events (See BVES AFN Plan, Section 4.2)
Access to BVES Representatives	Customers can reach live BVES representatives through an emergency hotline and dedicated support team during wildfire and PSPS events

12. Enterprise Systems

12.1 Targets

12.1.1 Qualitative Targets

Table 12-1. Enterprise Systems Targets below provides the targets for each initiative in the Enterprise System category.

Table 12-1 Enterprise Systems Targets

Initiative	Activity (Tracking ID #)	Previous Tracking ID (if applicable)	2026 End of Year Total / Completion Date	2027 Total / Status	2028 Total / Status	Section; Page number
Asset management and inspection enterprise system(s)	Conduct Annual Usefulness and Impact of Enterprise System Survey and Take Corrective Action on Results (ENT_1)	GD_34	100% Completed by December 31, 2026	100% Completed by December 31, 2027	100% Completed by December 31, 2028	12; p. 291
Vegetation management enterprise system	Conduct Annual Usefulness and Impact of Enterprise System Survey and Take Corrective Action on Results (ENT_2)	VM_15	100% Completed by December 31, 2026	100% Completed by December 31, 2027	100% Completed by December 31, 2028	12; p. 291

Grid Monitoring enterprise system	Develop and implement automatic SCADA alerts plan for staff. Grid Response Procedures and Notifications (GD_19)	GD_38	Automatic SCADA alert plan developed; December 2026	Automatic SCADA alert plan implemented; December 2027	N/A	8.7.2; p. 169
Ignition Detection enterprise system	Develop and implement automatic iSIU system alerts plan for staff. Autonomous Monitoring of Power Line Infrastructure (SAF_4)	SAF_7	Automatic iSIU system alert plan developed; December 2026	Automatic iSIU system alert plan implemented; December 2027	N/A	10.4.1; p. 235
Environmental Monitoring enterprise system	Develop and implement automatic weather station network alerts plan for staff. Advanced weather monitoring and weather stations (SAF_1)	SAF_1	Automatic weather station network alert plan developed; December 2026	Automatic weather station alert plan implemented; December 2027	N/A	10.2.1; p. 229
Risk Assessment enterprise system	Complete Integration of Direxyon and Technosylva Models - Risk Methodology and Assessment (RMA_1)	RMA_1	System integration started; January 2026	System integration completed; December 2027	N/A	5.7; p. 66

Bear Valley has established a qualitative target of one annual evaluation per year by multiple subject matter experts to determine the usefulness and impact of each enterprise system. Five SME that use the enterprise system on a daily basis, will respond to an annual survey to evaluate if the systems are meeting Bear Valley's needs and if there are any improvements that need to be addressed.

The survey for the Asset Management and Inspection Enterprise System(s) (ENT_1) will be taken by the following subject matter experts/users:

- Field Inspector
- Wildfire Mitigation and Reliability Engineer
- Utility Engineer and Wildfire Mitigation Supervisor
- Field Operations Supervisor
- Electric Distribution Systems Engineer

The survey for the Vegetation Management Enterprise System (ENT_2) will be taken by the following subject matter experts/users:

- Vegetation Pre-Inspector
- Forester
- Vegetation Management General Foreman
- Wildfire Mitigation and Reliability Engineer
- Utility Engineer and Wildfire Mitigation Supervisor

12.2 Summary of Enterprise Systems

Asset Management and Inspection Enterprise System(s) (ENT_1)

Bear Valley has taken steps to improve its asset management and inspection enterprise system over the last years. Data governance is an enabling investment that supports the overall effort of mitigating wildfires. Proper data governance will support the tracking of events that could lead to a wildfire, tracks the progress of electric system upgrades, and enables the ability to provide information to "other" parties.

Bear Valley uses the "iRestore" application and database to keep all records on assets and asset inspections. Bear Valley added a GO 165 Inspections Portal and a GO 174 Substation Inspection Portal. This created a reliable, searchable, comprehensive, and easily accessible database allowing BVES staff to continually meet or exceed all regulatory inspection requirements and achieve WMP inspection targets. Importantly, the enterprise system allows BVES to prioritize and track corrective action via work orders to inspection deficiencies and conduct trend analysis of work orders. The system also allows management to understand the scope of work orders and ensure resources are being properly allocated to completing any outstanding work orders. iRestore is a customizable database that BVES can mold to meet current and future needs.

Data entry and updates to the asset enterprise system is limited to a few selected and trained employees. These are the Field Inspector, Substation Technician, and Wildfire Mitigation and Reliability Engineer. Additionally, access is limited to the following supervisory element: Wildfire Mitigation and Reliability Engineer, Utility Engineer and Wildfire Mitigation Supervisor, and Electric Distribution Systems Engineer.

Data entry from contractor inspections is controlled on a case-by-case basis. For example, intrusive pole inspection results are entered by the contractor and checked by a Bear Employee. Access is limited to the data entry in this case.

Bear Valley controls the data integrity by limiting the access to the asset enterprise system to only to a small group of trained individuals who use the system as part of their responsibilities.

QA/QC is currently achieved by periodic supervisory reviews of asset enterprise system reports.

The application also has some built-in safeguards, such as the fact that inspection findings cannot be deleted from the application.

Bear Valley's staff is small and so effective asset enterprise system governance is achieved by limiting access to a small group of employees who are highly trained on the system.

Currently, all substation equipment, sub-transmission and distribution system assets are modeled in the system. All GO 165 and GO 174 inspections are recorded in the system.

Work orders are generated from inspection or condition findings.

The asset enterprise system was implemented by Bear Valley in the last two years. Bear Valley plans on integrating into the database the results of the following annual inspections:

- UAV Thermography Inspections
- UAV HD Photography/Videography Inspections
- 3rd Party Ground Patrol Inspections

Vegetation Management Enterprise System (ENT_2)

Bear Valley is implementing a new vegetation management enterprise system, Intelligent Vegetation Management System (IVMS), in 2025 created specifically to meet Bear Valley's requirements. This enterprise system will allow Bear Valley to catalog every tree within the service territory and document datasets on each tree. The system will be implemented by the end of 2025 and be in place for the period of this WMP. The database will include a significant amount of useful information for each including: circuit, GPS coordinates, address, species of tree, height of tree, all inspection and trim history, pictures of the tree before and after and work is conducted, and an individual tree ID numbers. Additional features include mobile device data acquisition, documentation of asset inspection findings, assignment of resolution priority, tracking status of resolution, and high-level finding analysis to determine if systemic issues exist.

The vegetation management crews have access to the application through iPads and mobile phones to document all the above inputs on all work completed. The Pre-Inspectors also have access to the application and enter all inspections into the database. The information from IVMS is also migrated into Bear Valley's GIS. IVMS has an audit system integrated into the application. Once plans are completed, auditors can QA/QC the work and re-assign them to crews as needed.

Satellite data acquisition of the entire overhead system, AiDASH uses proprietary Artificial Intelligence based algorithms to analyze the data to identify vegetation encroachment on utility power lines, hazard tree identification, as well as develop risk models for proactive and reactive vegetation management activities. This information is displayed and utilized when creating condition-based plans on IVMS. On sub-transmission and distribution lines, LiDAR and ground patrols are used to help tune the AiDASH model. The IVMS identifies, which year each circuit and/or segments of the system should be cleared based on current conditions and predicted growth. Cycle trimming varies by location and are developed through the AiDASH IVMS.

The IVMS analysis database creates a unique ID for each tree and holds extensive data on each tree (such as species, height, condition, etc.). The database will provide real-time vegetation inspection data available to users, trimming status, geolocation, among other things.

Data entry and updates to the asset enterprise system is limited to a few selected and trained employees. These are the Field Inspector, Forester, and Wildfire Mitigation and Reliability Engineer. Additionally, access is limited to the following supervisory element: Wildfire Mitigation and Reliability Engineer, Utility Engineer and Wildfire Mitigation Supervisor, and Electric Distribution Systems Engineer.

Data entry from contractor staff is limited to the pre-inspector and only the vegetation crews assigned to Bear Valley.

Bear Valley controls the data integrity by limiting the access to the IVMS to only to a small group of trained individuals who use the system as part of their responsibilities.

QA/QC is currently achieved by periodic supervisory reviews of asset enterprise system reports.

The application also has some built in safeguards, such as the fact that inspection findings cannot be deleted from the application.

Bear Valley's staff is small and so effective asset enterprise system governance is achieved by limiting access to a small group of employees who are highly trained on the system.

Work orders are generated from line clearance pre-inspections and vegetation management inspections. The IVMS allows Bear Valley to track open work orders by priority to completion and document their resolution.

As a future enhancement the IVMS, Bear Valley is also considering tagging trees with devices that electronically connect with mobile devices that crews and inspectors would use to increase accuracy of data collection and recording.

13. Lessons Learned

Bear Valley's 2026-2028 WMP builds upon the evolution of WMPs it has developed since its first WMP in 2019.

Bear Valley has not experienced a catastrophic wildfire ignited by its facilities or equipment. Bear Valley has incorporated the findings for its Substantial Vegetation Management Audits into its vegetation management program and Bear Valley has moved to improve its quality assurance programs through the WMP process based on feedback from the Independent Evaluator Annual Reports on Compliance.

Bear Valley has focused on improving the following areas in this WMP:

- Increased use of quantitative risk modeling in WMP initiative planning,
- Increased use of quantitative targets for WMP initiatives,
- Improved quality assurance practices for each of its WMP initiatives,
- Implementation of Fire Potential Index to drive grid operational decisions, and
- Developing a deliberate program for enhanced power line safety settings to be implemented in this WMP cycle.

The 2026-2028 WMP includes several improvements such as enhanced risk modeling capabilities as BVES digitizes its asset and inspection practices, more meaningful metric tracking calibrated across multiple internal reporting processes and platforms, and climate driven ignition probability maps that BVES will use to inform future initiative planning for areas of greatest wildfire risk.

BVES continuously monitors wildfire mitigation efforts. BVES conducts weekly Project Timeline meetings and weekly Management Briefs where the wildfire mitigation efforts are discussed. If any concern arises, Field Operations, the Engineering Department and Management will quickly find a resolution to the concern. Any concern will be discussed in the weekly meetings until a resolution is found. The lessons learned will be presented to the appropriate employees, contractors, and discussed in the weekly meetings. If a problem is discovered in the field or though inspections, this information will be forwarded to management and will be discussed in these weekly meetings.

In addition, BVES conducts a monthly management-employee Safety Committee Meeting in which any safety concerns will be discussed for wildfire mitigation measures. If a safety concern is discussed, then BVES staff, our health and safety consultant, and management will resolve the issue. A resolution to concerns and lessons learned will be immediately shared with the appropriate employees and the safety committee.

Major themes and lessons learned from the prior WMPs, periodic submissions, and experience with mitigation efforts provide valuable insight into BVES's continuous improvement efforts. Bear Valley has fortunately experienced positive results in executing and implementing mitigation strategies and has not experienced a utility-ignited wildfire incident or had reason to activate a PSPS event. Issues or delays in execution are addressed upon identification throughout the year. BVES continues to provide an open line of communication among the WMP responsible personnel up to and including the President. If a change of strategy is warranted, the appropriate department heads discuss potential actions and monitor any changes. Each quarter, the President meets with the Board of Director's Safety and Operations Committee, which encompasses governing body members of the Company, to discuss any issues identified during the prior quarter and will discuss proposed alternatives in strategy. This process enables a feedback loop for continuous improvement.

13.1 Description and Summary of Lessons Learned

Table 13-1. Lessons Learned provides a list of lesson learned.

Table 13-1 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	2020-2023	Permitting	Grid Design, Operations, and Maintenance	The permitting process with the US Forrest Service is a lengthy and challenging process/	The USFS has a very heavy workload in addition to its permitting work and has a very small staff to accomplish the workload. Additionally, the USFS has many permit requests to process and does not necessarily have the internal capability to determine which requests need to be processed as a high priority. Therefore, it is beneficial engage the USFS staff early and frequently to emphasize the priority of the project; especially, wildfire mitigation initiatives.	Situational. Currently, BVES does not have any projects requiring significant USFS permitting.	Radford Line Replacement Project
2	2024	Fire Potential Index (FPI)	Situational Awareness and Forecasting	Implementation of FPI has provided BVES more granularity in evaluating operational actions to mitigate wildfire risk.	Circulating FPI to staff every day raises the situational awareness on the wildfire risk for the day and helps drive the right operational decisions each day to ensure the distribution system is operated in a safe manner.	Currently implements. BVES will continue to review its effectiveness each year as an ongoing effort.	2026-2028 WMP Section 10.6
3	2023	Supply Chain	Grid Design, Operations, and Maintenance	Procurement lead time for large and technically advanced electrical equipment (substation transformers, intelligent switchgear and reclosers, capacitor banks, etc.) is extremely lengthy (15-18 months).	Procurement of electrical equipment must be performed as soon as feasible due to the long lead times. When this is coupled with permitting time and GRC approval time, a project can easily extend out to 3-5 years.	Currently implemented in BVES's planning process.	N/A
4	2023	Risk based planning	Risk Methodology and Assessment and Wildfire Mitigation Strategy	By transitioning to risk models that provide risk analysis at the segment level, BVES is now able to prioritize its grid hardening efforts in its highest risk spots with significant precision.	Utilize Technosylva's FireSight model to prioritize WMP initiatives.	BVES has transitioned to utilizing quantitative risk modeling (Technosylva's FireSight) in prioritizing WMP Initiatives.	2026-2028 WMP Section 6

5	2023-2024	Community engagement	Emergency Preparedness, Collaboration, and Community outreach	Apply findings from public safety partners and community coordination throughout the year to inform future planning	Drawing upon lessons learned from other California utilities, BVES has increased its community engagement activities over 2021 from 2020 as well as engaging more broadly with the direct public safety partners within the service area.	Ongoing	2026-2028 WMP Section 11
6	2023-2024	PSPS Preparation	Emergency Preparedness, Collaboration, and Community outreach	The feedback from Drills and Table Top Exercises are vital to the advancement of BVES programs, specifically those related to PSPS	Drills and Table Top Exercises have led to enhancements for training PSPS response teams by (1) Elevated exercise complexity with interactive elements to simulate real-world scenarios; (2) Role-specific training and action cards for individual practice and training; and (3) Backup training to bolster operational readiness and response capability	Ongoing	2026-2028 WMP Section 11
7	2023-2024	PSPS Response	Emergency Preparedness, Collaboration, and Community outreach	Lessons learned from other IOUs is leading to improved PSPS Response	IOUs have collectively reported that utilities made strides to enhance collaboration with Public Safety Partners	2026-2028 WMP	2026-2028 WMP Section 11
8	2023-2024	PSPS Customer Impact Mitigation	Emergency Preparedness, Collaboration, and Community outreach	Lessons learned from other IOUs is leading to improved PSPS Response	Reduce customer burden for the access and functional needs (AFN) population and disadvantaged communities (DACs), through improved notification systems and Community Resource Centers (CRCs). Additional CRC amenities considered with a focus on additional charging units.	2026-2028 WMP	2026-2028 WMP Section 11

9	2023-2024	PSPS Communication and Notification Improvements	Emergency Preparedness, Collaboration, and Community outreach	Lessons learned from other IOUs is leading to improved PSPS Response	Addressing concerns regarding excessive or inaccurate notifications to customers and Public Safety Partners. Customers report being frustrated with too much communication. Allow customers to select notification options.	2026-2028 WMP	2026-2028 WMP Section 11
10	2023-2024	PSPS Operational Coordination and Standardization	Emergency Preparedness, Collaboration, and Community outreach	Lessons learned from other IOUs is leading to improved PSPS Response	Standardizing naming conventions and processes across different operational aspects to minimize confusion and errors. During tabletop exercises, participants reported confusion in the naming convention. Ensure simple naming conventions when disseminating information. Consider colors/numbers and clear/concise naming. Consider using an unfamiliar audience to see if they can understand the convention.	2026-2028 WMP	2026-2028 WMP Section 11
11	2023-2024	PSPS Situational Awareness and Training	Emergency Preparedness, Collaboration, and Community outreach	Lessons learned from other IOUs is leading to improved PSPS Response	Providing further training and standardization to ensure all personnel are proficient in hosting operational briefings and calls. During tabletop exercises, participants reported confusion in the naming convention. Adopt a standard template and memo for communication per topic and customer group. Conduct position-specific training to improve situational awareness, especially regarding scope changes during PSPS events.	2026-2028 WMP	2026-2028 WMP Section 11

12	2023	Covered Conductor Working Group	Grid Design, Operations, and Maintenance	The utilities agree that it is helpful to share information, practices, and data across the utilities as this can lead to improvements in reducing wildfire risk, safety incidents, and the impacts of PSPS, and improvements with other utility objectives. Several shared discussions of materials and procedures have helped improved BVES's covered conductor program.	Covered conductors working group reports have provided an excellent technical basis for making grid design and maintenance decisions.	Ongoing	2026-2028 WMP Section 8
13	2023-2024	Risk Model Working Group	Risk Methodology and Assessment	The Risk Model Working Group has provided BVES with significant amount of detailed information concerning Risk Modeling especially from the other Utilities.	The information gained can help shape how BVES uses its risk modeling resources and makes decisions moving forward.	Ongoing	RMWG Reports
14	2023	Utility Vegetation Management Best Practices for Wildfire Safety	Vegetation Management and Inspection	The meeting on Utility Vegetation Management Best Practices for Wildfire Safety has provided BVES with beneficial insight into considerations for vegetation management program improvements.	The information gained can help shape how BVES implements its vegetation management and inspection programs.	Ongoing	Meeting report.

13.2 Working Group Meetings

Bear Valley attends all of Energy Safety-required working group meetings including those planned for 2025. The following working groups are discussed:

- **Covered Conductor Working Group:** BVES found that it was beneficial to share information, practices, and data across the utilities as this can lead to improvements in reducing wildfire risk, safety incidents, and the impacts of PSPS, and improvements with other utility objectives. Several shared discussions of materials and procedures have helped improved BVES's covered conductor program. Widespread use of covered conductors to mitigate wildfire is a relatively new phenomena; therefore, this working group was critical to accelerating the learning curve so that informed decisions could be made as BVES moved to harden its facilities utilizing covered conductors.

- **Risk Model Working Group:** The Risk Model Working Group has provided BVES with significant amount of detailed information and insight concerning Risk Modeling that California electric utilities are utilizing and developing. This is a relatively new area for BVES (in the last 5 years); therefore, understanding what is possible and where further development is needed was critical to the decisions BVES made in its developing in the area of Risk Modeling and Assessment. Small electric utilities such as BVES, do not have the resources to quickly hire experienced experts; so, hearing from experts from across the IOUs; especially, the large IOUs was extremely beneficial.

- **Utility Vegetation Management Best Practices for Wildfire Safety:** The meeting on Utility Vegetation Management Best Practices for Wildfire Safety has provided BVES with beneficial insight into considerations for vegetation management program improvements. First, it provided a viewpoint from two experts in the field of utility vegetation management. Then the working group began to address issues such as (1) hazard tree Inspection, including off-ROW hazard management; (2) remote sensing integration (LiDAR, Satellite, drone); and (3) efficient distribution ROW management, including Integrated Vegetation Management/ "Forest Resilience Corridors."

- **Joint IOU Wildfire Program Management Meetings:** Bear Valley is a member of this group and regularly attends its monthly meetings. The group acts as a central hub for facilitating decision making, benchmarking, and the formulation of best practices across the IOUs related to wildfire mitigation work. The meeting includes sharing of best practices, discussion of issues and problems encountered with possible solutions, new technologies and approaches, and lessons learned. Besides providing invaluable content used in developing or refining WMP initiatives, the meetings establish strong working relationships among the IOUs such that IOUs can reach out to each other outside of the meeting venue on WMP issues.

13.3 Discontinued Activities

Bear Valley does not have any discontinued initiatives. Therefore, **Table 13-2. Lessons Learned from Discontinued Activities** does not have any discontinued initiatives listed.

Table 13-2 Lessons Learned from Discontinued Activities

Discontinued Activity (Tracking ID)	Rationale for Discontinuation	Lessons Learned	Replacement Activities (include page # where discussed)
None	N/A	N/A	N/A

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.

Terms Defined in Other Codes

Where terms are not defined in these Guidelines and are defined in the Government Code, Public Utilities Code, or Public Resources Code, such terms have the meanings ascribed to them in those codes.

Terms Not Defined

Where terms are not defined through the methods authorized by this section, such terms have ordinarily accepted meanings such as the context implies.

Definition of Terms

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.
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 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) 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].)
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 degree of resistance to control; similar to burning index, but without effects of wind speed.[3]

[3] National Wildfire Coordinating Group: https://www.nwcg.gov/node/393188 (accessed May 9, 2024).

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.[4]
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.[5]
Fuel density	Mass of fuel (vegetation) per area that could combust in a wildfire.
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.[6]
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.

[4] National Wildfire Coordinating Group: https://www.nwcg.gov/node/447140 (accessed May 9, 2024).
[5] National Wildfire Coordinating Group: https://www.nwcg.gov/node/444281 (accessed May 9, 2024).
[6] National Wildfire Coordinating Group: https://www.nwcg.gov/node/386549 (accessed May 9, 2024).

Grid hardening	Actions (such as equipment upgrades, maintenance, and planning for more resilient infrastructure) taken in response to the risk of undesirable events (such as outages) or undesirable conditions of the electrical system to reduce or mitigate those events and conditions, informed by an assessment of the relevant risk drivers or factors.
Grid topology	General design of an electric grid, whether looped or radial, with consequences for reliability and ability to support PSPS (e.g., ability to deliver electricity from an additional source).
Hazard	A condition, situation, or behavior that presents the potential for harm or damage to people, property, the environment, or other valued resources.
Hazard tree	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.[7]

[7] https://mesonet.agron.iastate.edu/request/gis/watchwarn.phtml.

HWW overhead (OH) circuit mile day	Sum of OH circuit miles of utility grid subject to a HWW each day within a given time period, calculated as the number of OH circuit miles under a HWW multiplied by the number of days those miles are under said HWW. For example, if 100 OH circuit miles are under a HWW for one day, and 10 of those miles are under the HWW for an additional day, then the total HWW OH circuit mile days would be 110.
Ignition 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).
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.
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).[8]
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.

[8] Adapted from SFPE, 2010, "Substantiating a Fire Model for a Given Application," *Society of Fire Protection Engineers Engineering Guides*.

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.
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.
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 7potential	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.
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. [9]
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.)
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:

[9] Adapted from D. Coppola, 2020, "Risk and Vulnerability," *Introduction to International Disaster Management*, 4th ed.

	• 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.)
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. [10]
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. [11]
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.

[10] 121 https://www.nwcg.gov/node/439827 (assessed May 13, 2024).
[11] California Public Resources Code section 4525.7.

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.
Utility-related ignition	An event that meets the criteria for a reportable event subject to fire-related reporting requirements. [12]
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.

[12] CPUC Decision 14-02-015, Appendix C, page C-3: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M087/K892/87892306.PDF.

Wildfire consequence	The total anticipated adverse effects from a wildfire on a community that is reached. This considers the wildfire hazard intensity, the wildfire exposure potential, and the inherent wildfire vulnerabilities of communities at risk.
Wildfire exposure potential	The potential physical, social, or economic impact of wildfire on people, property, critical infrastructure, livelihoods, health, environmental services, local economies, cultural/historical resources, and other high-value assets. This may include direct or indirect impacts, as well as short- and long-term impacts.
Wildfire 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.
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 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.
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.
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.

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.

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 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.
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 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.
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

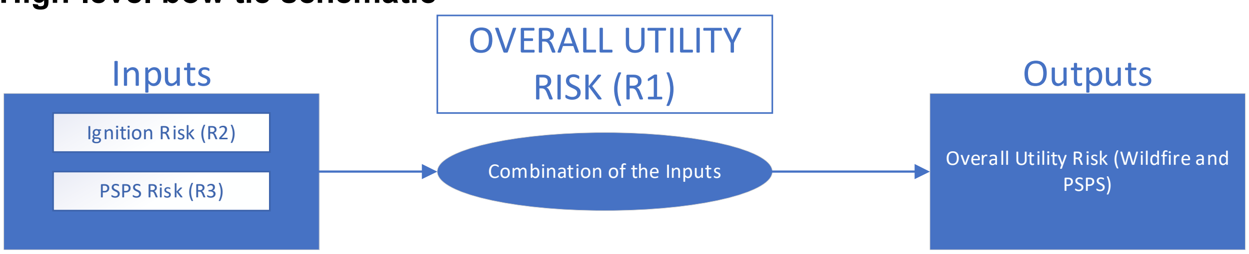
B.1 Model Inventory

The models used by Technosylva are identified in their report provided in Section B.4. Since the DIREXYON program was not used to develop this WMP, a list is not provided here. BVES has included the details of the DIREXYON summary documentation in Section B.2, as its implementation is intended to be completed in 2025

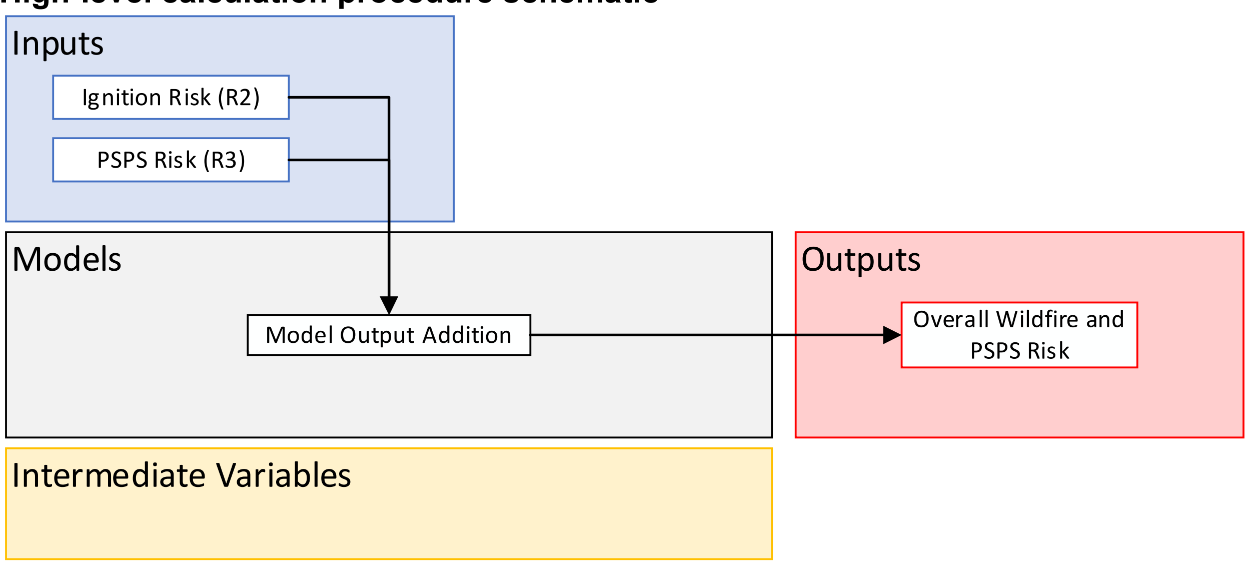
B.2 Summary Documentation

B.2.1 Overall Utility Risk (R1)

High-level bow tie schematic



High-level calculation procedure schematic



High-level narrative

- *Purpose of the calculation/model*

The Overall Utility Risk is a combination of Ignition Risk and PSPS Risk and is intended to provide the overall risk by circuit.

- *Assumptions and limitations*

The Overall Utility Risk is based on sub-component calculations such as ignition likelihood, wildfire consequence, etc. These calculations have built in assumptions and limitations that would carry through to the Overall Utility Risk calculation.

- *Description of the calculation procedure shown in the bow tie and high-level schematics*

Overall Utility Risk is the addition of Ignition Risk and PSPS Risk.
With the incorporation of the DIREXYON model, BVES will be able to calculate wildfire risk at a greater level of precision. The image below provides insight into the calculation that is used by the DIREXYON model to determine risk level at the circuit level. The DIREXYON model uses the data provided by Technosylva to calculate wildfire risk levels. Fire risk and PSPS components of the model constitute the core of the model. The fire risk assessment integrates multiple factors, including asset related characteristics, equipment ignition, and vegetation contact. Simultaneously, the PSPS risk assessment considers wildfire spread, hazard intensity, exposure potential and community vulnerability, providing a comprehensive overview of the network's resilience to both fire-related incidents and PSPS events. All the calculations are considering three weather trends, categorized as optimistic, normal, and pessimistic, based on Technosylva percentiles.

Asset Value Information for Period 2026

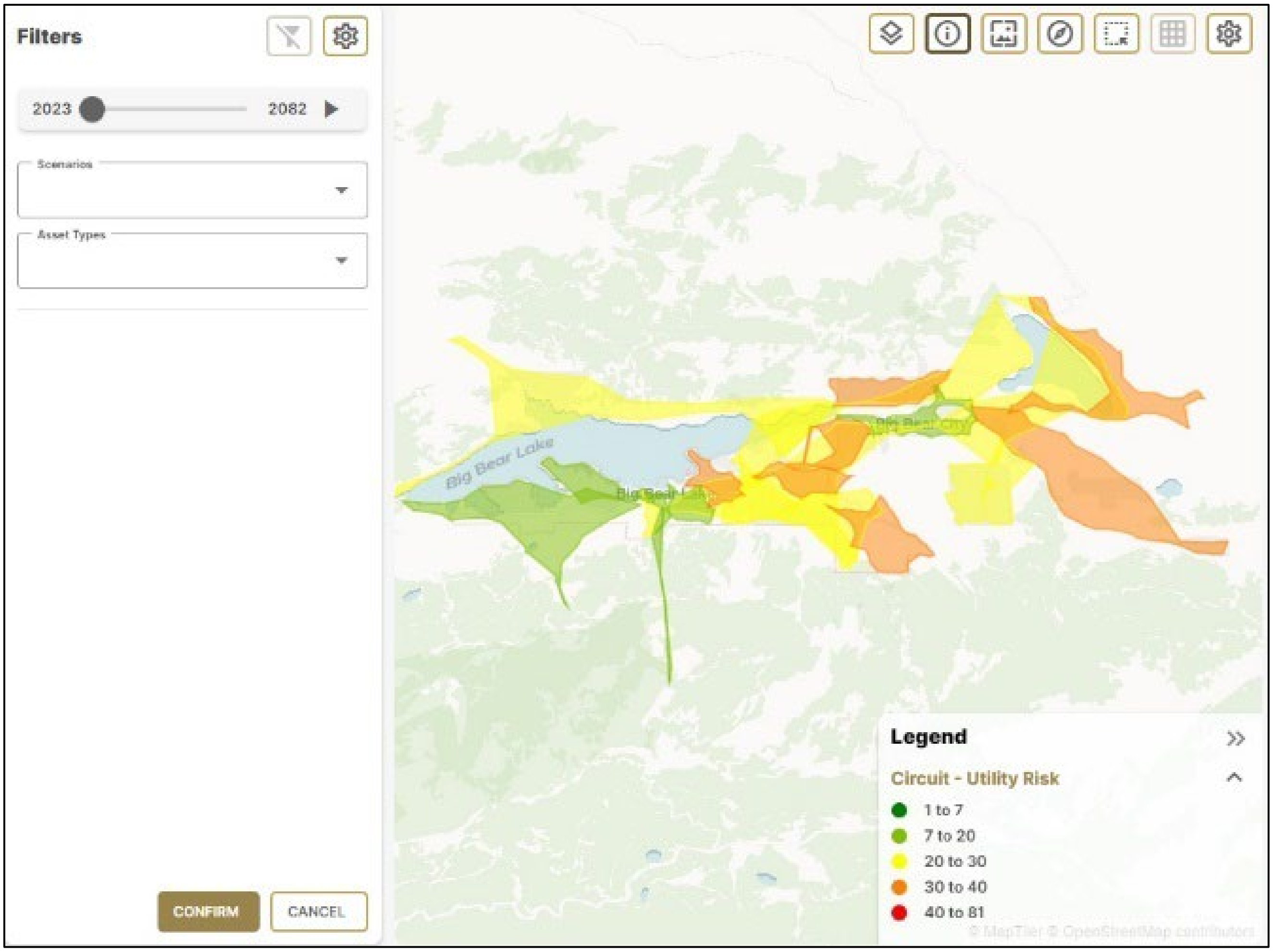
Characteristic [Utility Risk] calculation
End of Step

(0.5 x 4.973) + (0.5 x 14.27) = 9.621

(123 Configurable FireRisk weight x Fire Risk) + (123 Configurable PSPS weight x fx PSPS - Risk) = fx Utility Risk

- *Description of how outputs will be characterized and presented (e.g., visualization) to decision makers*

BVES will be able to use Overall Utility Risk and its sub-components (Ignition Risk and PSPS Risk) and present them as values to the decision makers to aid in determination of mitigation initiative prioritization. In its most common form will be the use of output values but heat maps of the outputs may also be used.
Through the implementation of the DIREXYON model, that utilizes the Technosylva data, BVES can track the journey of each asset in each year based on each iteration, verifying the evolution of asset characteristics over time. This format enables validation of specific interventions triggered at precise moments, providing insights into their impacts. In addition to the individual asset level data, BVES can also view aggregated results within the DIREXYON risk models. The DIREXYON model presents simulation outcomes in an aggregated format, offering a holistic view of the overall network condition, required investments, and other key performance indicators at a collective level. This format facilitates a comprehensive evaluation of the network's overall health and performance. The integrated dashboard within the DIREXYON risk models offers BVES versatile views, tailored to cater to various roles such as executives, asset managers, and more. These views can seamlessly switch between detailed insights and holistic overviews, providing a customized experience for different stakeholders (please see the image below to see the Power BI views available to BVES through the DIREXYON risk models).

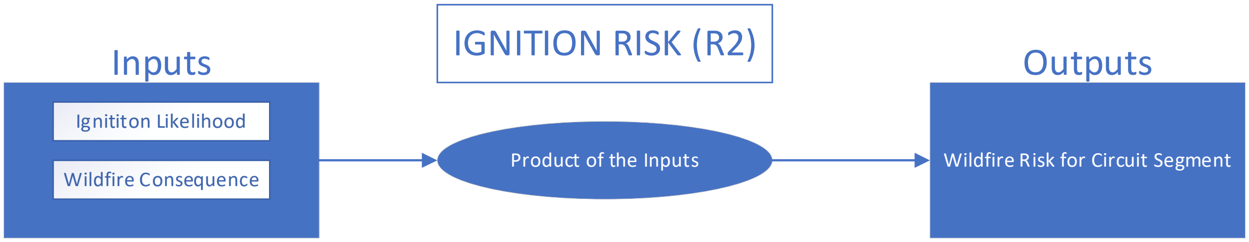


- *Concise description and timeline of planned changes to the calculation procedure over the triennial WMP cycle, including any key improvements from the Energy Safety Wildfire Risk Modeling Working Group and plans to align with the consensus Risk Modeling Requirements by January 1, 2024.*

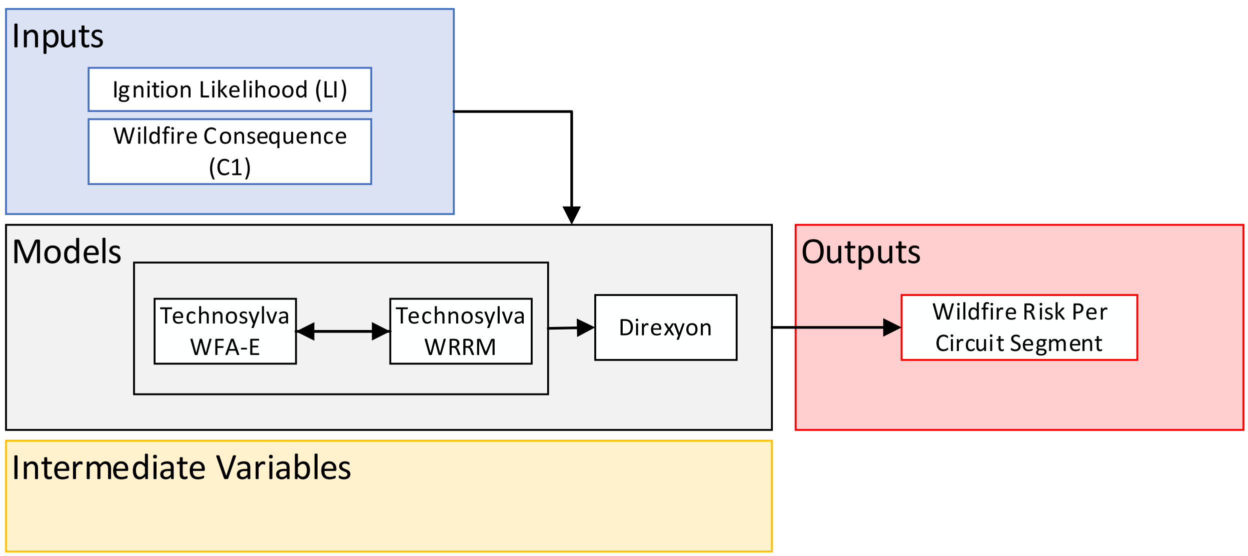
BVES will review feedback from the working groups that it has been involved in including the Wildfire Risk Model Working Group and assess the need for improvements or changes. BVES plans to include more data and documentation for this risk model/component in future WMPs. Additionally, BVES plans to complete formal implementation and staff training on the WFA-E model to develop proficient model users and implement use of the WRRM and FPI in evaluating asset risks.

B.2.2 Ignition Risk (R2)

High-level bow tie schematic



High-level calculation procedure schematic



High-level narrative

- *Purpose of the calculation/model*

The ignition risk model by DIREXYON can also be understood as wildfire risk. It is designed to demonstrate the geospatial risk of ignition and the associated expected consequences of BVES's assets, equipment, and operations across the service territory.

- *Assumptions and limitations*

The risk calculation is based on assumptions and limitations from more granular sub-components (e.g., likelihood of ignition, wildfire consequences, etc.). This model assumes all like equipment, vegetation, and other factors behave in the same manner under the expected conditions. The models are limited by ability to fully adjust for combined mitigation affects. Additionally, areas that appear similarly on mapping and modeling often have great variation among sites. For example, the entry of the presence of Tier 3 HFTD designation may not reflect stretches of sparse vegetation or cleared ground under overhead equipment.

- *Description of the calculation procedure shown in the bow tie and high-level schematics*

Ignition or Wildfire Risk in the DIREXYON risk models is a multiplication of the Ignition Likelihood and Wildfire Consequence.

- *Description of how outputs will be characterized and presented (e.g., visualization) to decision makers*

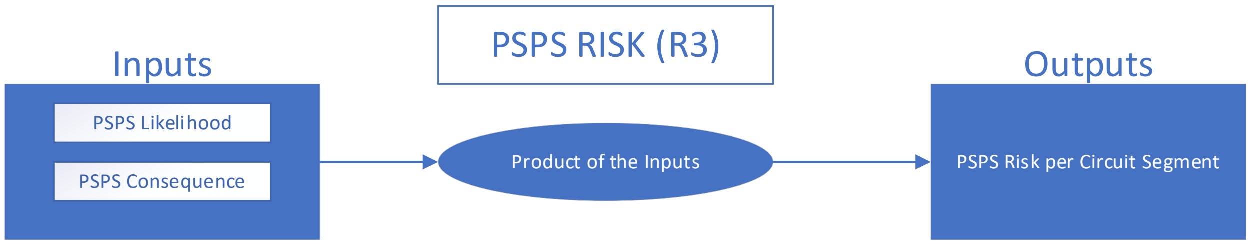
Ignition or wildfire risk in the DIREXYON models can be broken down into its two components (ignition likelihood and wildfire consequence).

- *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.*

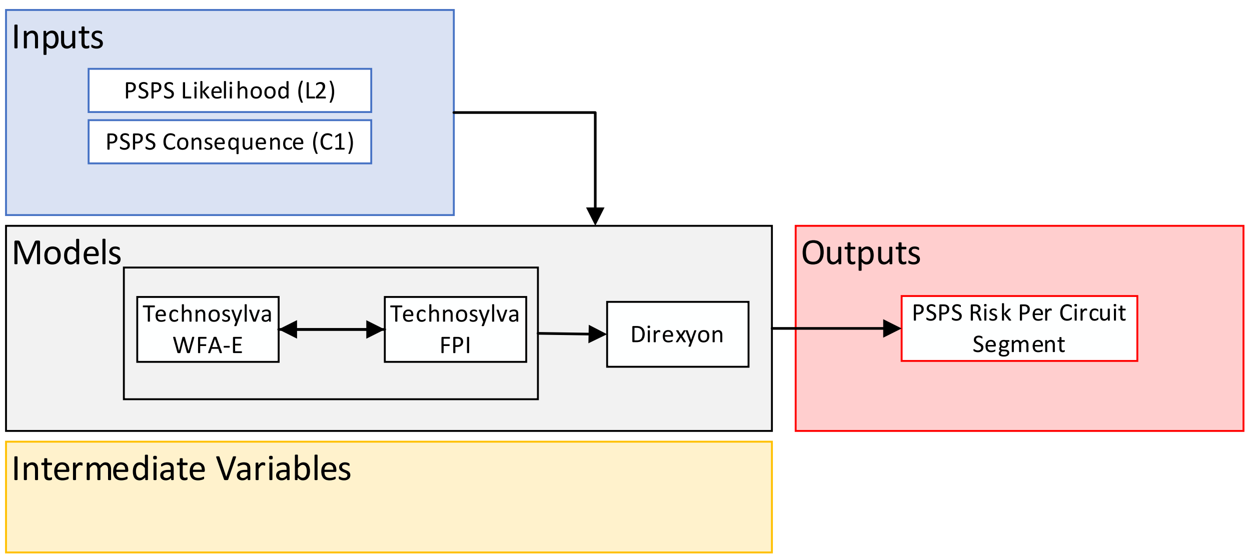
BVES will review feedback from the working groups that it has been involved in including the Wildfire Risk Model Working Group and assess the need for improvements or changes. BVES plans to include more data and documentation for this risk model/component in future WMPs. Additionally, BVES plans to complete formal implementation and staff training on the WFA-E model to develop proficient model users and implement use of the WRRM in evaluating asset and wildfire risks.

B.2.3 PSPS Risk (R3)

High-level bow tie schematic



High-level calculation procedure schematic



High-level narrative

- *Purpose of the calculation/model*

For the PSPS risk, the DIREXYON model calculates the overall PSPS risk, based on two inputs – PSPS likelihood and PSPS consequences.

- *Assumptions and limitations*

The risk calculation is based on assumptions and limitations from more granular sub-components – PSPS likelihood and PSPS consequences.

- *Description of the calculation procedure shown in the bow tie and high-level schematics*

In the DIREXYON model, PSPS risk is a product of PSPS likelihood and PSPS consequences.

PSPS risk assessment considers wildfire spread, hazard intensity, exposure potential and community vulnerability, providing a comprehensive overview of the network's resilience to PSPS events

The DIREXYON risk model computes PSPS risk at the circuit level, and the cumulative risk at circuit level contributes to the overall utility risk of the network. Similar to the fire risk, PSPS risk comprises two components: probability of PSPS and consequence of PSPS:

Asset Value Information for Period 2026

Characteristic [PSPS - Risk] calculation
End of Step

3.114 x 4.583 = 14.27

PSPS - Consequences x PSPS - Probability Score = PSPS - Risk

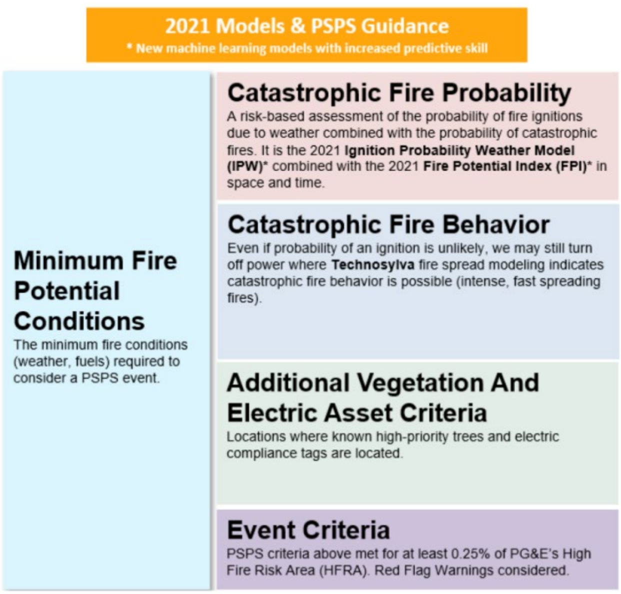


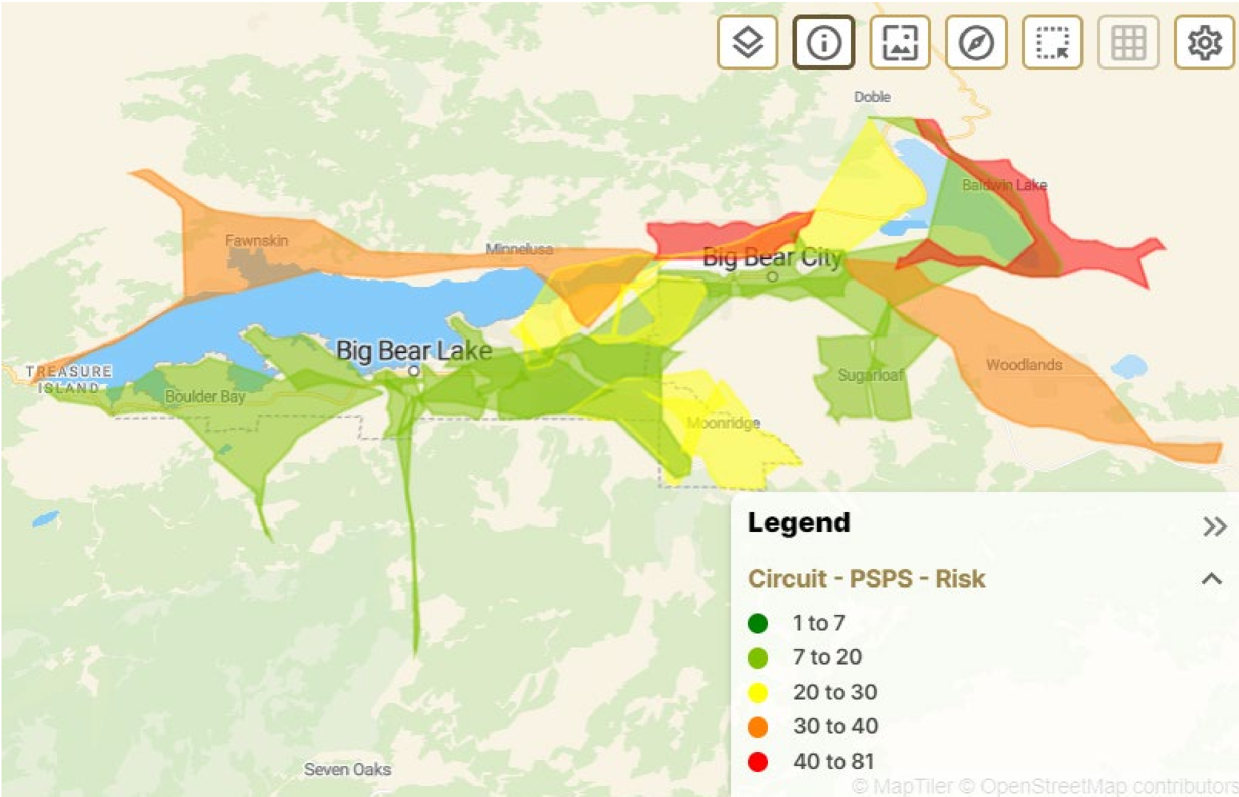
Fig. 1. High level overview of 2021 Distribution PSPS guidance

Fire behavior classes (1-5) are defined in segment level based on two components of Techno-sylva that is Fire Rate of Spread, and Flame length.

FIRE BEHAVIOR CLASS		ros (ch/h) 100 ch/h = 1.25 mi/h					
		VERY LOW	LOW	MODERATE	HIGH	VERY HIGH	EXTREME
	0	0 - 2	2 - 5	5 - 20	20 - 50	50 - 150	>150
fl (ft) VERY LOW	0 - 1	1	1	1	1	2	3
LOW	1 - 4	1	1	2	2	3	4
MODERATE	4 - 8	1	2	2	3	4	5
HIGH	8 - 12	1	2	3	3	4	5
VERY HIGH	12 - 25	2	3	3	4	5	5
EXTREME	>25	3	3	4	4	5	5

- *Description of how outputs will be characterized and presented (e.g., visualization) to decision makers*

In the DIREXYON risk model, PSPS Risk components (likelihood and consequences) can be shown individually or shown as a single risk score per circuit, depending on the purpose of the presentation. There is the individual asset level debug screen, as well as the aggregated results BI dashboard. An example of the view is shown in the image below.

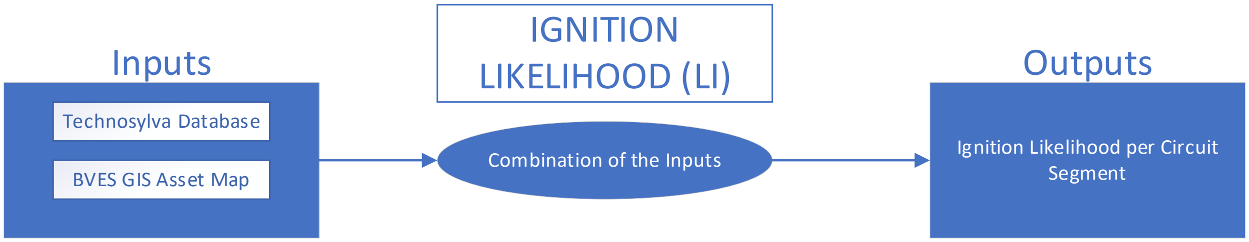


- *Concise description and timeline of planned changes to the calculation procedure over the triennial WMP cycle, including any key improvements from the Energy Safety Wildfire Risk Modeling Working Group and plans to align with the consensus Risk Modeling Requirements by January 1, 2024.*

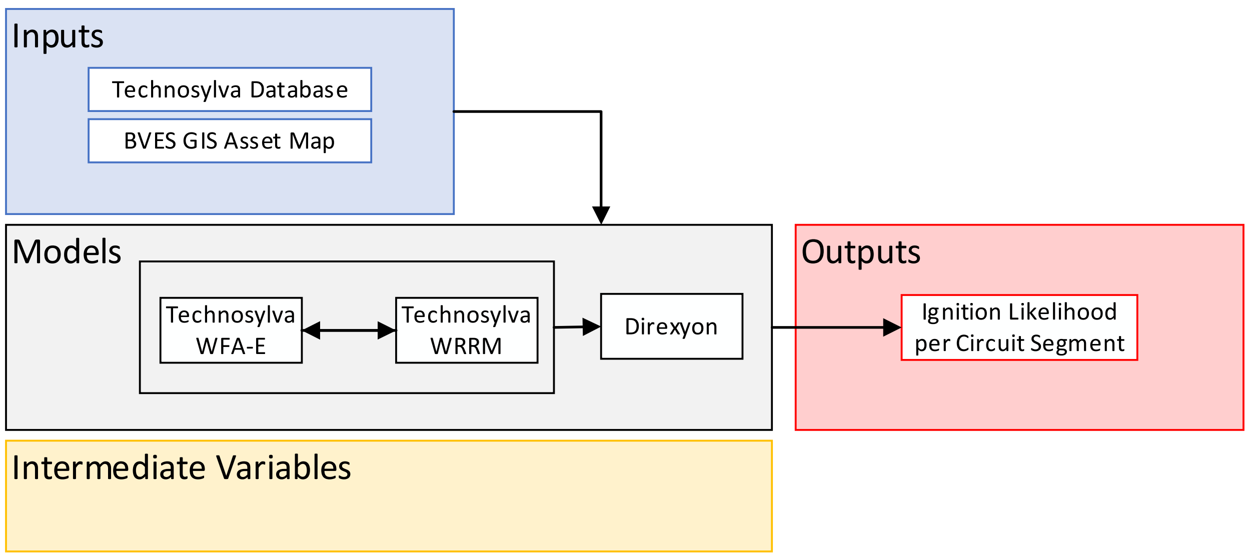
BVES will review feedback from the working groups that it has been involved in including the Wildfire Risk Model Working Group and assess the need for improvements or changes. BVES plans to include more data and documentation for this risk model/component in future WMPs. Additionally, BVES plans to complete formal implementation and staff training on the WFA-E model to develop proficient model users and implement use of the WRRM and FPI in evaluating PSPS risks.

B.2.4 Ignition Likelihood (LI)

High-level bow tie schematic



High-level calculation procedure schematic



High-level narrative

- *Purpose of the calculation/model*

In the DIREXYON model, ignition likelihood is synonymous with probability of ignition, which is based on inputs of the risk likelihood models (e.g., Equipment Likelihood of Ignition, Contact from Vegetation Likelihood, and Contact from Object Likelihood).

- *Assumptions and limitations*

The probability of ignition is a probabilistic assessment of each asset's pre-mitigated ignition likelihood (wildfire likelihood) prior to mitigation deployment.

- *Description of the calculation procedure shown in the bow tie and high-level schematics*

LI is the sum of the ignition component probabilities at that location (i.e., equipment ignition likelihood, contact from vegetation ignition likelihood, and contact by object ignition likelihood.

- *Description of how outputs will be characterized and presented (e.g., visualization) to decision makers*

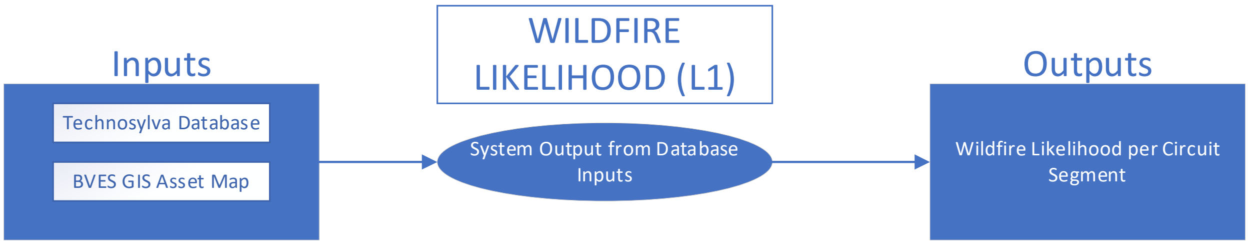
Ignition likelihood can be broken down into its components (i.e., equipment ignition likelihood, contact from vegetation ignition likelihood, and contact by object ignition likelihood) and can be further broken down into individual contact types and equipment failures.

- *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.*

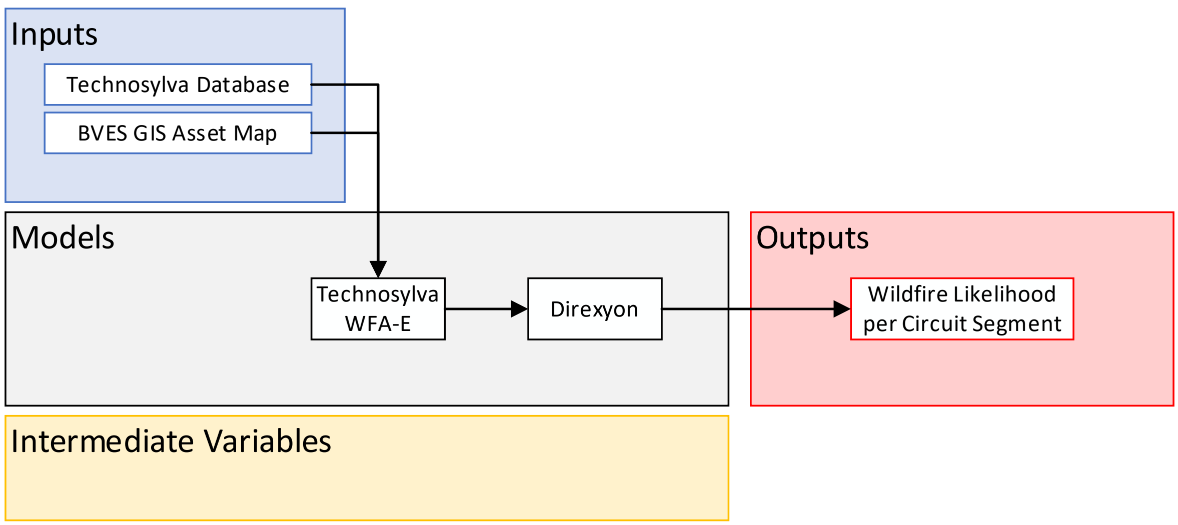
BVES will review feedback from the working groups that it has been involved in including the Wildfire Risk Model Working Group and assess the need for improvements or changes. BVES plans to include more data and documentation from Technosylva for this risk model/component in future WMPs. Additionally, BVES plans to complete formal implementation and staff training on the WFA-E model to develop proficient model users and implement use of the WRRM and FPI in evaluating asset, fire, and PSPS risks.

B.2.5 Wildfire Likelihood (L1)

High-level bow tie schematic



High-level calculation procedure schematic



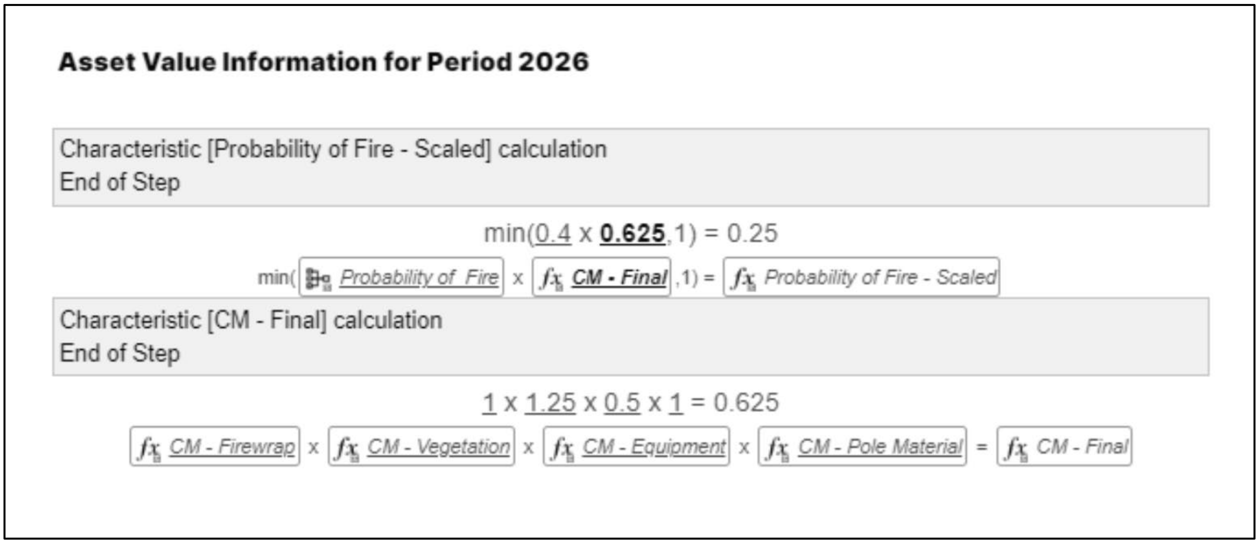
High-level narrative

- *Purpose of the calculation/model*

Understanding the wildfire likelihood per circuit segment.

- *Assumptions and limitations*
- *Description of the calculation procedure shown in the bow tie and high-level schematics*

BVES has enhanced their risk modeling efforts through implementation of Technosylva and DIREXYON. The DIREXYON model utilized Technosylva data to develop a holistic risk overview that encompasses wildfire likelihood. The probability of fire gauges the likelihood of fire ignition specific to each asset type. It is calculated as the product of the Technosylva-calculated Probability of Ignition (POI) and XY condition modifiers (CMs). The image below represents the probability of fire risk calculations along with overall CM calculations for poles.



XY Condition modifiers

Condition modifiers in the model are to show the impact of asset characteristics and specific interventions on the calculated probability of fire by Technosylva. For example, if a bare conductor is replaced with a covered conductor, what is the impact on probability of fire? Accordingly, the following condition modifiers are defined in individual asset levels as detailed below:

Conductor Condition Modifiers

Conductor Material:

This modifier assesses the effect of conductor material (such as copper or other materials) on overall fire risk. Notably, copper conductors are associated with a higher probability of igniting a fire. Consequently, substituting copper conductors with non-copper materials reduces the fire risk by 50%, while the reverse—replacing non-copper materials with copper—increases the risk by 50%. Please note that, the 50% values are a placeholder in the model that needs to be adjusted with more insights from subject matter experts.

This nuanced approach enables users to quantify the potential risk mitigation or escalation associated with changes in conductor types.

Conductor Type:

This condition modifier delineates the effects of various conductor types, specifically comparing covered and uncovered variants. Transitioning from uncovered to covered conductors notably diminishes the associated fire risk. Consequently, implementing coverings on previously non-covered conductors results in a 50% reduction in fire risk. Please note that this value is taken from available literature and serves as a placeholder in the model, and with further insight from BVES and access to historical events correlated with conductor types, adjustments can be made for a more accurate assessment.

Accordingly, the conductor probability of fire is the product of Technosylva-calculated Probability of Ignition (POI), CM – Conductor Material, and CM – Conductor type.

These two condition modifiers specifically address the equipment ignition likelihood within the identified gap.

Transformer Condition Modifiers

Transformer failure:

This condition modifier encapsulates the impact of transformer degradation on the probability of fire. Transformer degradation is characterized by age and different Kva ratings. Additionally, an asset-specific accidental failure probability of 0.002 is incorporated into the risk/failure model. In the absence of historical failure data from BVES, the accidental failure probability of 0.002 serves as a placeholder, derived from the findings of a study by S. Tenbohlen (2011)(5).

The current condition modifier for transformers is derived from a Weibull failure curve, considering transformer age, KVA, and accidental failure probability. Specifically, for a brand-new transformer or pole, the condition modifier (CM) is 1. As transformers age, the CM exponentially increases from 1 to 2.

The 0.2% probability of accidental failure for transformers addresses the Contact by Object Ignition Likelihood within the identified gap.

This data provides valuable insights into the potential risks associated with transformer conditions.

Pole Condition Modifiers

Fire Wrap:

This condition modifier assesses the impact of installing fire wraps on wooden poles as a risk mitigation measure. Accordingly, the installation of fire wraps on wooden poles initially without them can result in a 10% reduction in probability of fire.

Pole material:

This condition modifier evaluates the impact of pole material on fire risk, with wooden poles generally posing a higher risk of ignition compared to metal poles. The modifier facilitates an understanding of the potential risk reduction by replacing wooden poles with steel in the network. Currently, replacing wood material with non-wood reduces the fire risk by 10%.

Vegetation

Vegetation is incorporated into the model as an integral part of the pole asset type. The likelihood of fire caused by vegetation varies based on the state of trees—whether they have fallen, grown, or the overall tree density (Fall in, Grow in, and Tree density). Markov chains are employed to model the probability of transitioning from the best zone (4) to the worst zone (1), dependent on the number of years since the last vegetation inspection.

For all three mentioned metrics, a zone value is predicted annually based on the elapsed time since the last vegetation management intervention. Consequently, with an increasing number of years since the last vegetation management intervention, the probability of transitioning from the best zones to the worst zones rises. In simpler terms, without regular inspections, there is a heightened risk of the vegetation around the equipment growing unchecked, thereby increasing the likelihood of fires.

The final CM vegetation is the product of three Condition Modifiers (CMs) CM – Fall in, CM – Grow in, and CM – Density. For each metric if the tree's state remains unaltered compared to the initial state, the related CM is set at 1. However, if it deteriorates, the CM adjusts from 25% to 100% (based on the initial and current zones), and if it improves, it decreases by 25% to 75%. This meticulous approach ensures a nuanced representation of the impact of vegetation on fire risk within the model. Please note that this value serves as a placeholder, and with further insight from BVES and access to historical fall-in and grow-in data, adjustments can be made for a more accurate assessment. Each of the identified metrics is briefly explained below:

<u>Grow-In</u>

This metric relies on a shape file provided by BVES, representing the likelihood of tree branches growing into power lines and causing fires. The clear level in the data interprets the Grow-in values.

<u>Fall-In</u>

Data for this metric is sourced from a shape file provided by BVES. Calculated based on tree height and the distance of the tree to the pole, Fall-In zones are defined depending on the minimum height required for a tree to impact an asset. This determination considers the pole height, tree distance to pole, and the specified minimum heights.

<u>Density</u>

Data for this metric comes from the VegManagementDataPartner, with no specific aggregation performed on the dataset. It represents the density of vegetation around the assets.

These condition modifiers address the contact from vegetation ignition likelihood within the identified gap.

<u>Equipment</u>

A pole linked to high-risk equipment, such as a transformer and/or conductor, inherently carries an elevated fire risk. This condition modifier encapsulates the cumulative effect of calculated Condition Modifiers (CMs) for transformers and conductors, providing a comprehensive assessment of the associated risk for a given pole.

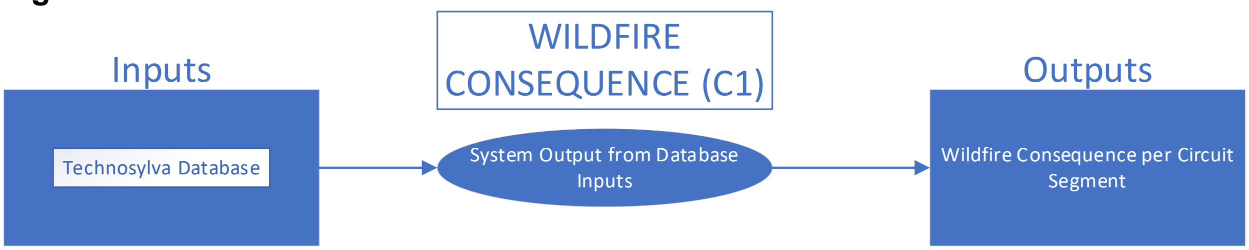
- *Description of how outputs will be characterized and presented (e.g., visualization) to decision makers.*

- *Concise description and timeline of planned changes to the calculation procedure over the triennial WMP cycle, 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.*

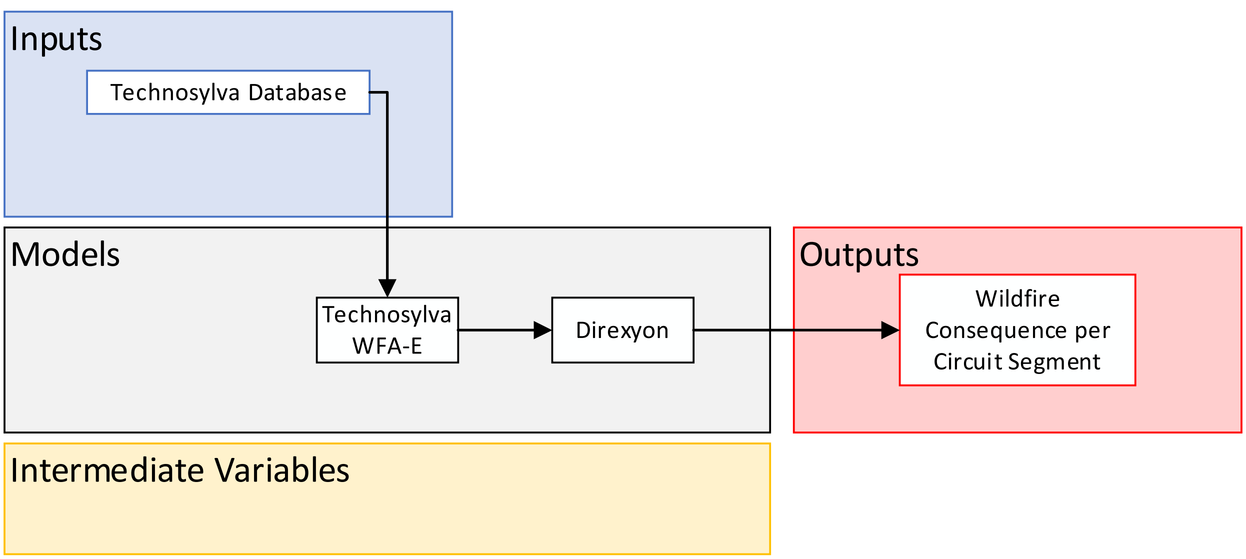
BVES will review feedback from the working groups that it has been involved in including the Wildfire Risk Model Working Group and assess the need for improvements or changes. BVES plans to include more data and documentation for this risk model/component in future WMPs. Additionally, BVES plans to complete formal implementation and staff training on the WFA-E model to develop proficient model users and implement use of the WRRM and FPI in evaluating wildfire risks.

B.2.6 Wildfire Consequence (C1)

High-level bow tie schematic



High-level calculation procedure schematic



High-level narrative

- *Purpose of the calculation/model*

The purpose of the model it to assess wildfire consequence based on match-drop simulations for utility asset locations.

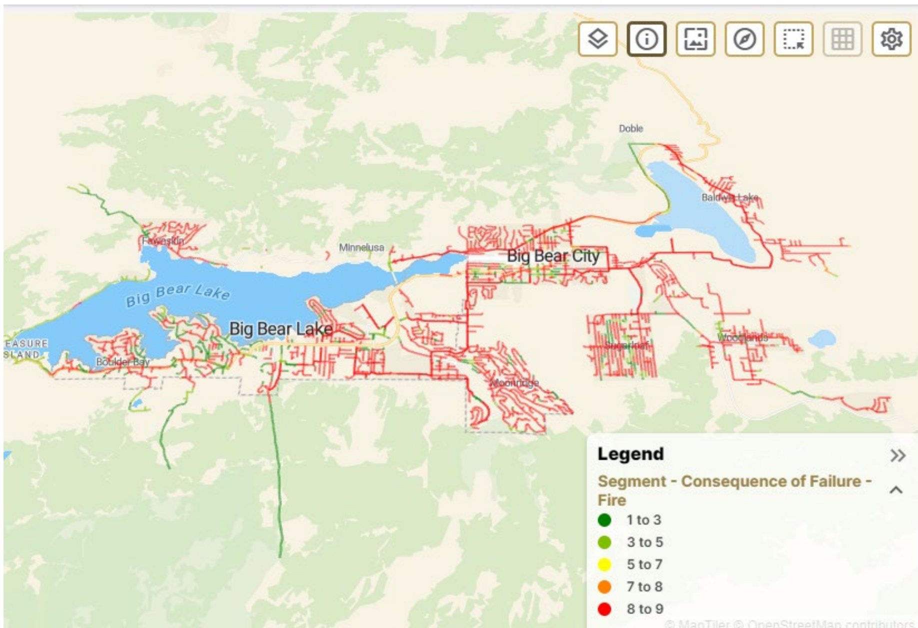
- *Assumptions and limitations*

- *Description of the calculation procedure shown in the bow tie and high-level schematics.*

Consequence of fire values delineate the impact of fire on population, buildings destroyed, and acres burned. These values, determined by Technosylva at the segment level, remain constant across all asset types within the same segment. The mentioned consequences are grouped into safety, environmental, and finance impact with user-defined weights that can be easily adjusted upon running the simulation.

- *Description of how outputs will be characterized and presented (e.g., visualization) to decision makers*

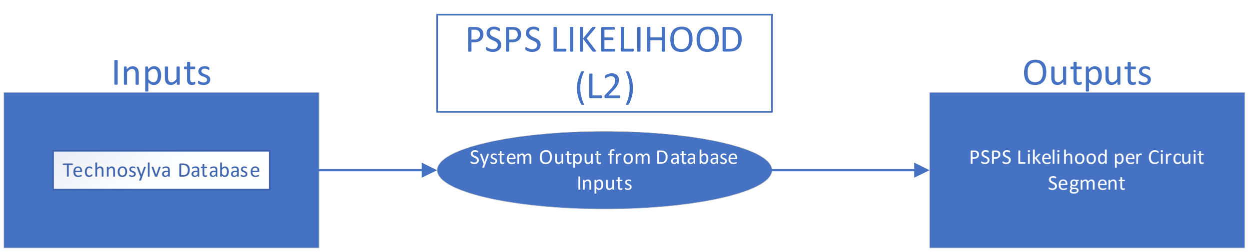
The attached screenshot represents the calculated consequence of fire in segment level based Technosylva data and configurable weights. In the DIREXYON model, the location of area that can be highly affected by fire can be visualized on a map as bellow:

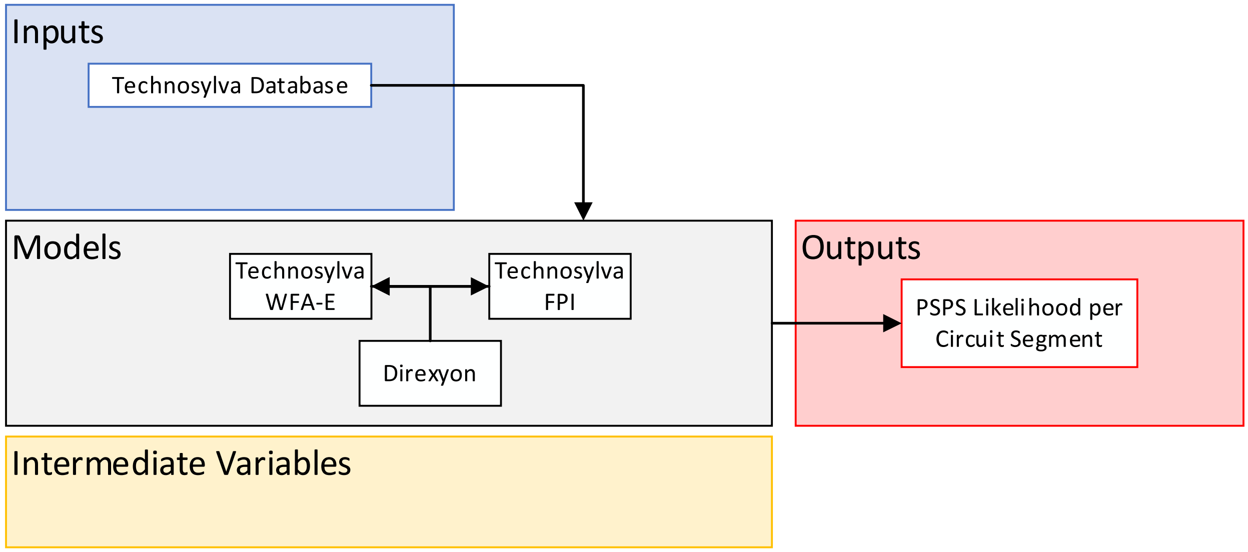


- *Concise description and timeline of planned changes to the calculation procedure over the triennial WMP cycle, including any key improvements from the Energy Safety Wildfire Risk Modeling Working Group and plans to align with the consensus Risk Modeling Requirements by January 1, 2024.*

BVES will review feedback from the working groups that it has been involved in including the Wildfire Risk Model Working Group and assess the need for improvements or changes. BVES plans to include more data and documentation for this risk model/component in future WMPs. Additionally, BVES plans to complete formal implementation and staff training on the WFA-E model to develop proficient model users and implement use of the WRRM and FPI in evaluating wildfire risks and consequences.

B.2.7 PSPS Likelihood (L2)





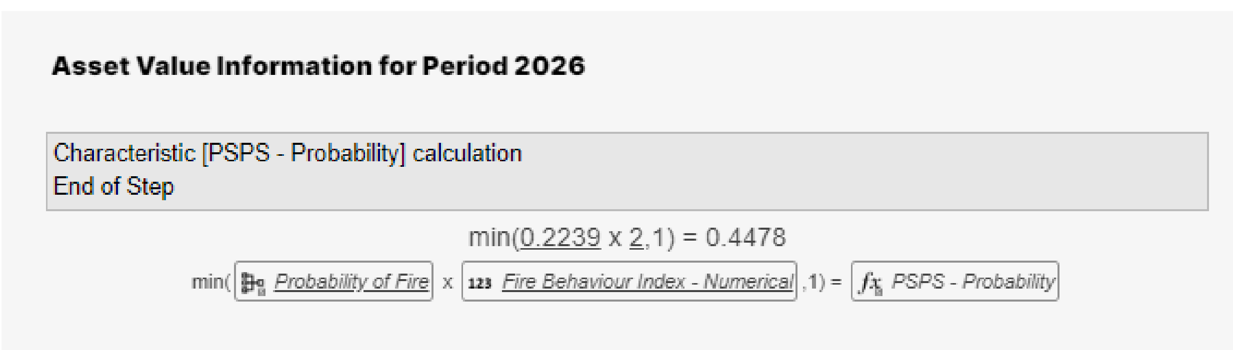
High-level narrative

- *Purpose of the calculation/model*

The purpose of the calculation is to determine the PSPS likelihood for a given circuit segment given data inputs.

- *Assumptions and limitations*
- *Description of the calculation procedure shown in the bow tie and high-level schematics*

In the absence of FPI data from Technosylva and based on the available literature by PG&E (6), PSPS probability is defined based on calculated fire probabilities in individual asset levels (POI*CMs) and fire behavior index.

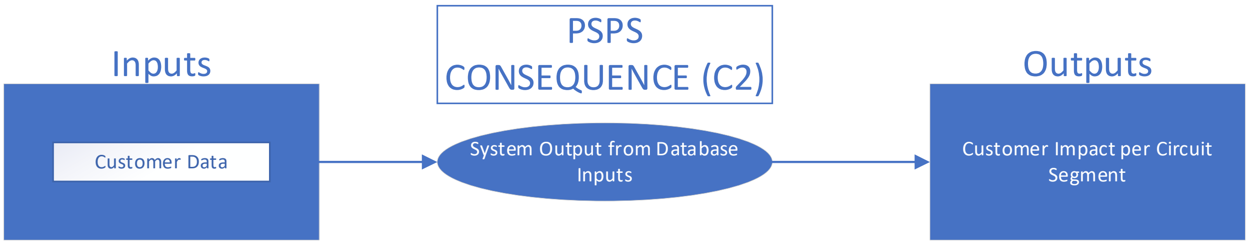


- *Description of how outputs will be characterized and presented (e.g., visualization) to decision makers*
- *Concise description and timeline of planned changes to the calculation procedure over the triennial WMP cycle, including any key improvements from the Energy Safety Wildfire Risk Modeling Working Group and plans to align with the consensus Risk Modeling Requirements by January 1, 2024.*

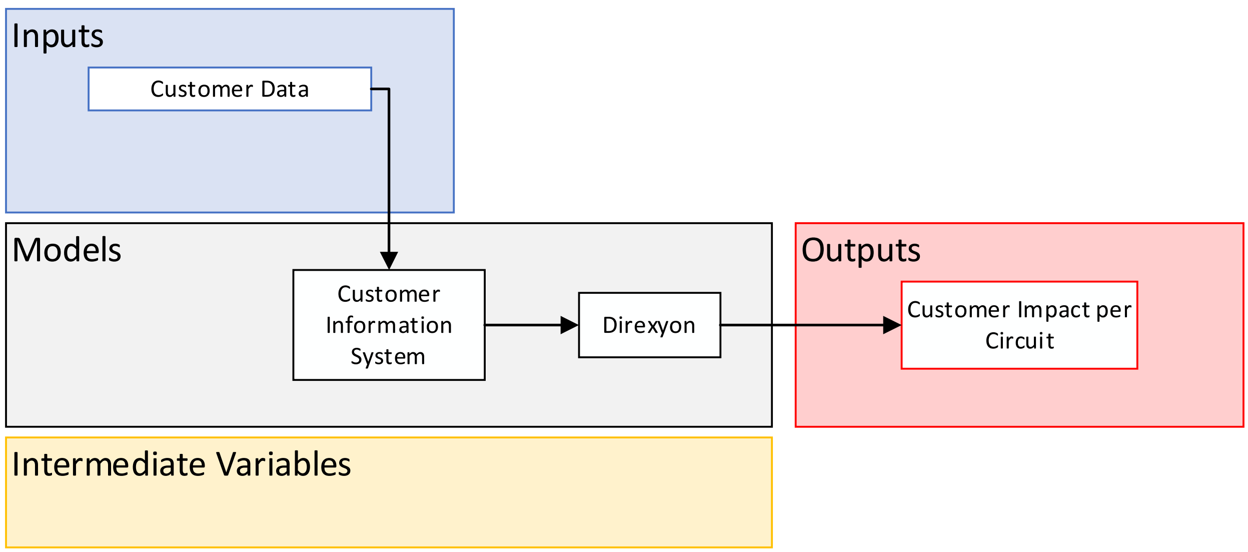
BVES will review feedback from the working groups that it has been involved in including the Wildfire Risk Model Working Group and assess the need for improvements or changes. BVES plans to include more data and documentation for this risk model/component in future WMPs.

B.2.8 PSPS Consequence (C2)

High-level bow tie schematic



High-level calculation procedure schematic



High-level narrative

- *Purpose of the calculation/model*

The purpose of the calculation is to determine the projected customer impact for a given circuit segment in the form of customer per circuit.

- *Assumptions and limitations*
- *Description of the calculation procedure shown in the bow tie and high-level schematics*

PSPS Consequence values outline the repercussions of Public Safety Power Shutoffs (PSPS) on distinct categories, including vulnerable individuals (AFN customers), the general population, and affected buildings. These consequences are categorized into PSPS vulnerability and PSPS exposure, with customizable user-defined weights that can be easily adjusted upon running the simulation.

Asset Value Information for Period 2026

Characteristic [PSPS - Consequences] calculation
End of Step

(0.5 x 1) + (0.5 x **5.227**) = 3.114

(123 Configurable PSPS Vulnurability Consequence Weight x *fx* PSPS - Vulnerability) + (123 Configurable PSPS Exposure Consequence Weight x *fx* **PSPS - Exposure**) = *fx* PSPS - Consequences

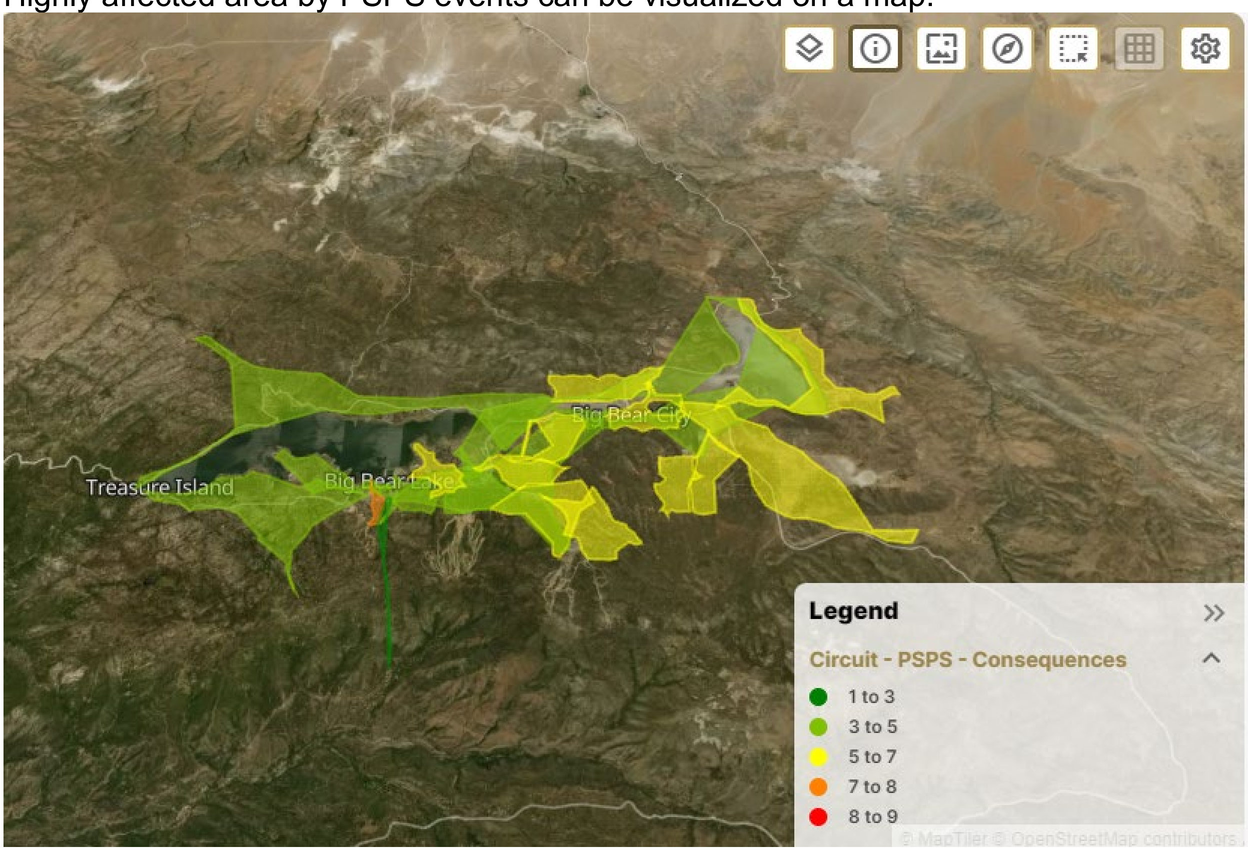
Characteristic [PSPS - Exposure] calculation
End of Step

(0.25 x 5.863) + (0.75 x 5.016) = 5.227

(123 Building Destroyed Impact Configurable Weight (PSPS) x Building Destroyed Impact - Score) + (123 Population Impact Configurable Weight (PSPS) x Population Impact - Score) = *fx* PSPS - Exposure

- *Description of how outputs will be characterized and presented (e.g., visualization) to decision makers*

Highly affected area by PSPS events can be visualized on a map:



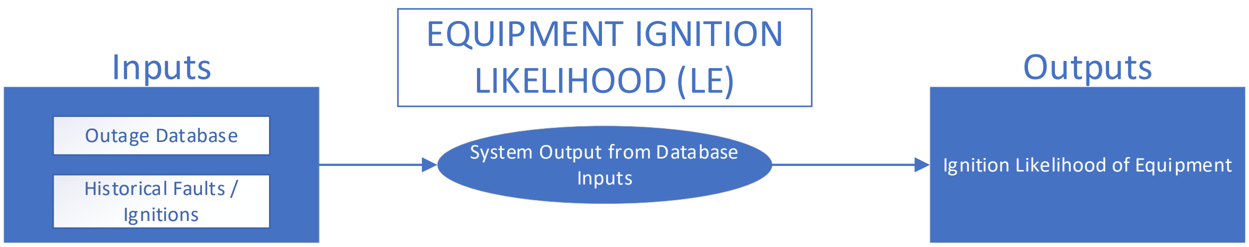
- *Concise description and timeline of planned changes to the calculation procedure over the triennial WMP cycle, including any key improvements from the Energy*

> *Safety Wildfire Risk Modeling Working Group and plans to align with the consensus Risk Modeling Requirements by January 1, 2024.*

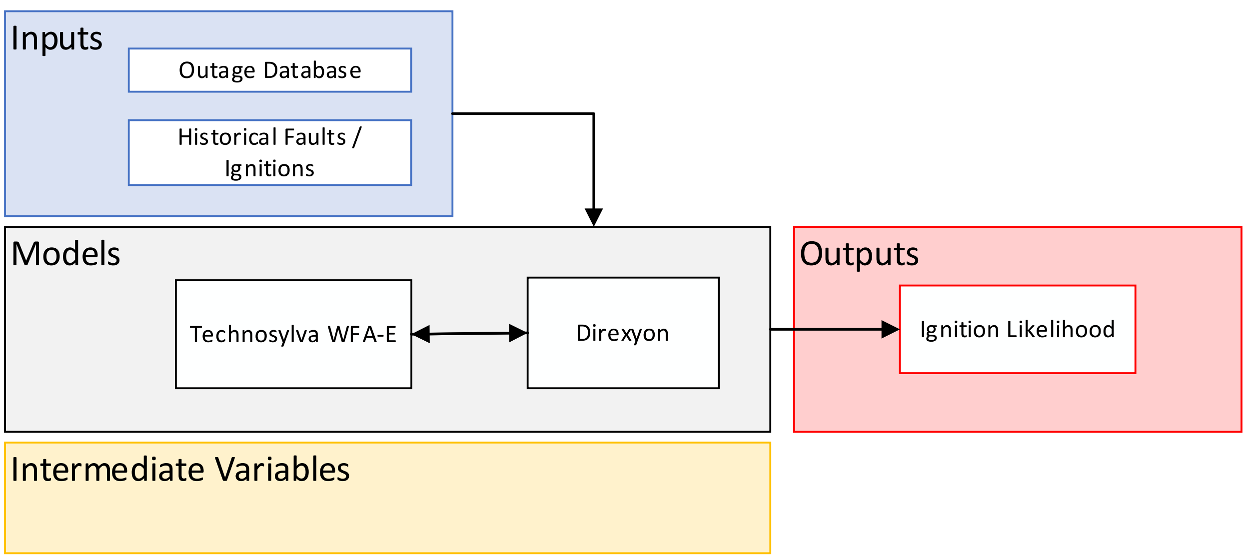
BVES will review feedback from the working groups that it has been involved in including the Wildfire Risk Model Working Group and assess the need for improvements or changes. BVES plans to include more data and documentation for this risk model/component in future WMPs. Additionally, BVES plans to complete formal implementation and staff training on the WFA-E model to develop proficient model users and implement use of the WRRM in evaluating PSPS risks and consequences.

B.2.9 Equipment Ignition Likelihood (LE)

High-level bow tie schematic



High-level calculation procedure schematic



High-level narrative

BVES collaborated with DIREXYON to introduce a new risk modeling tool to BVES's wildfire risk mitigation practices. The model is completed; however, as of the date of this filing the model is not fully implemented. BVES staff are completing training by DIREXYON on the model and BVES will need to set certain modifier values and risk weightings before the model is fully operational. BVES expects the model to be in full operation by Q4 2024. Updates to Appendix B including the addition of the DIREXYON's White Paper have been made as part of BVES Risk Modeling updates. The following paragraphs describe the DIREXYON risk model.

- *Purpose of the calculation/model*

The purpose of the model is to identify the impact of asset/equipment characteristic in probability of fire. For example, calculating probability of fire for a bare conductor vs cover conductor and showing the risk reduction by covering conductor. According to the literature, there is a higher chance of copper conductor to catch on fire and cause a wildfire.

- *Assumptions and limitations*
- *Description of the calculation procedure shown in the bow tie and high-level schematics*

BVES has enhanced their risk modelling efforts through the incorporation of DIREXYON. DIREXYON builds asset models and has defined condition modifiers to identify the impacts of wildfire that is caused by equipment ignition. For the current phase of the project, conductor type and material are used to estimate the equipment ignition likelihood as bellow:

Conductor Material

This modifier assesses the effect of conductor material (such as copper or other materials) on overall fire risk. Notably, copper conductors are associated with a higher probability of igniting a fire. Consequently, substituting copper conductors with non-copper materials reduces the fire risk by 50%, while the reverse—replacing non-copper materials with copper—increases the risk by 50%. This nuanced approach enables users to quantify the potential risk mitigation or escalation associated with changes in conductor types.

Conductor Type

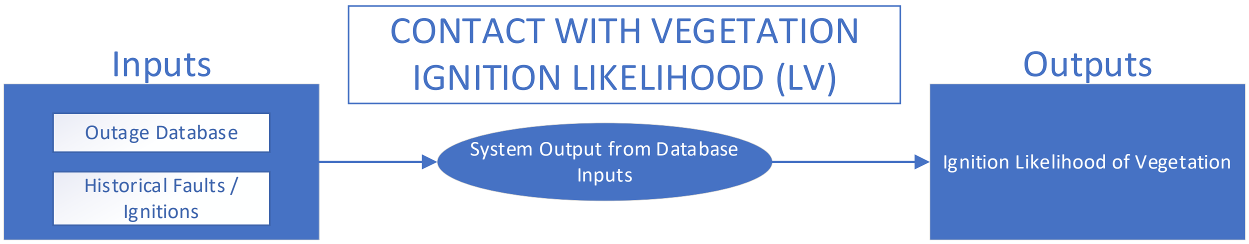
This condition modifier delineates the effects of various conductor types, specifically comparing covered and uncovered variants. Transitioning from uncovered to covered conductors notably diminishes the associated fire risk. Consequently, implementing coverings on previously non-covered conductors results in a 50% reduction in fire risk. Accordingly, the conductor probability of fire is the product of Technosylva-calculated Probability of Ignition (POI), CM – Conductor Material, and CM – Conductor type.

- *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, 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.*

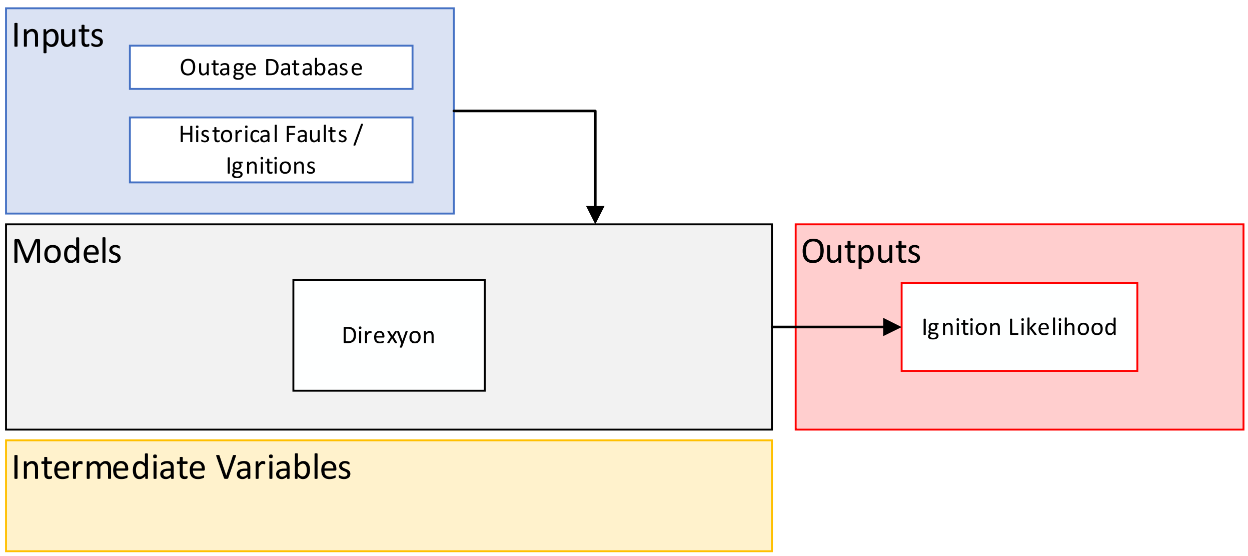
BVES will review feedback from the working groups that it has been involved in including the Wildfire Risk Model Working Group and assess the need for improvements or changes. BVES plans to include more data and documentation for this risk model/component in future WMPs. Additionally, BVES plans to complete formal implementation and staff training on the WFA-E model to develop proficient model users and implement use of the WRRM and FPI in evaluating wildfire risks including equipment ignition likelihood.

B.2.10 Contact with Vegetation Ignition Likelihood (LV)

High-level bow tie schematic



High-level calculation procedure schematic



High-level narrative

- *Purpose of the calculation/model*
- *Assumptions and limitations*
- *Description of the calculation procedure shown in the bow tie and high-level schematics*

BVES has brought in DIREXYON to enhance our risk modelling efforts that incorporates the likelihood of fire caused by vegetation into their models, which varies based on the vegetation—whether they have fallen, grown, or the overall tree density (fall in, grow in, and tree density). Markov chains are employed to model the probability of transitioning from the best zone (4) to the worst zone (1), dependent on the number of years since the last vegetation inspection.

For all three mentioned metrics, a zone value is predicted annually based on the elapsed time since the last vegetation management intervention. Consequently, with an increasing number of years since the last vegetation management intervention, the probability of transitioning from the best zones to the worst zones rises. In simpler terms, without regular inspections, there is a heightened risk of the vegetation around the equipment growing unchecked, thereby increasing the likelihood of fires. The final CM vegetation is the product of three Condition Modifiers (CMs) CM – Fall in, CM – Grow in, and CM – Density. For each metric if the tree's state remains unaltered compared to the initial state, the related CM is set at 1. However, if it deteriorates, the CM adjusts from 25% to 100%

(based on the initial and current zones), and if it improves, it decreases by 25% to 75%. This meticulous approach ensures a nuanced representation of the impact of vegetation on fire risk within the model. Each of the identified metrics is briefly explained below:

Fall-In

Data for this metric is sourced from a shape file provided by BVES. Calculated based on tree height and the distance of the tree to the pole, Fall-In zones are defined depending on the minimum height required for a tree to impact an asset. This determination considers the pole height, tree distance to pole, and the specified minimum heights.

Density

Data for this metric comes from the VegManagementDataPartner, with no specific aggregation performed on the dataset. It represents the density of vegetation around the assets.

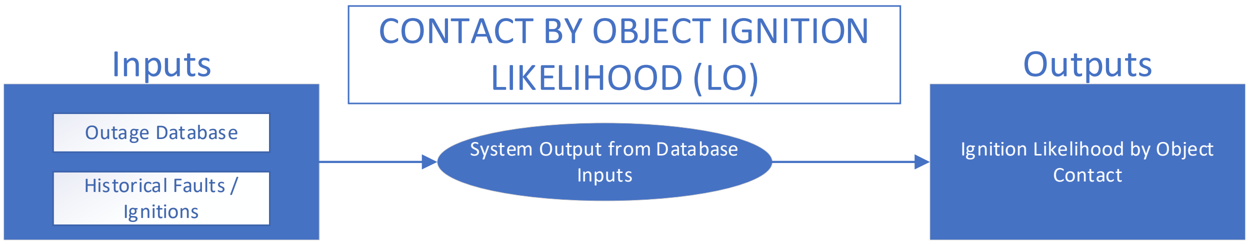
These condition modifiers address the contact from vegetation ignition likelihood within the identified gap.

- *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, 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.*

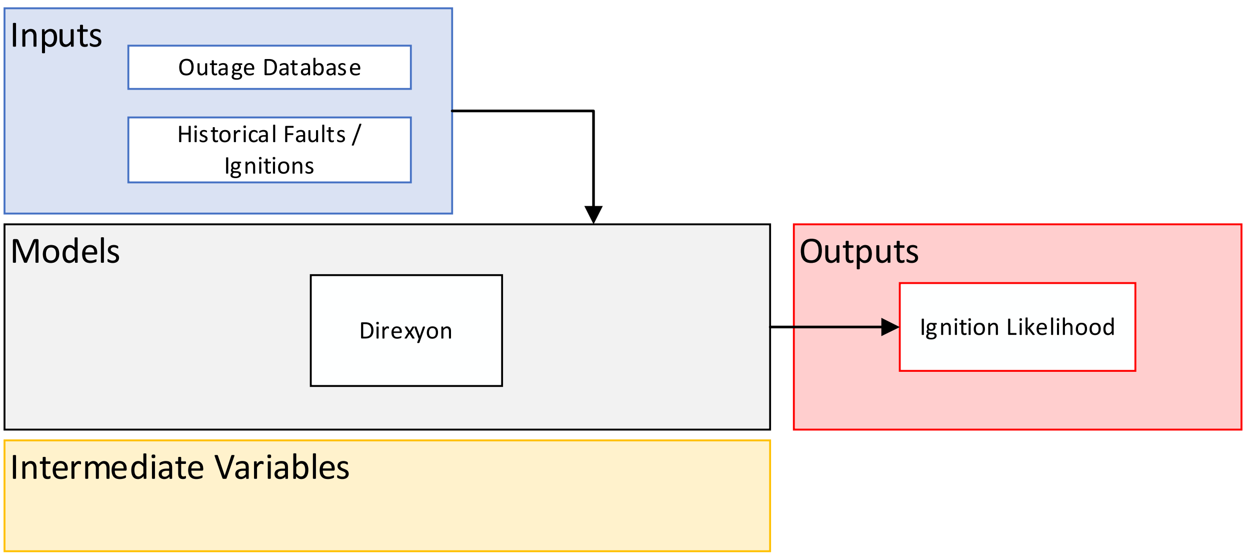
BVES will review feedback from the working groups that it has been involved in including the Wildfire Risk Model Working Group and assess the need for improvements or changes. BVES plans to include more data and documentation for this risk model/component in future WMPs. Additionally, BVES plans to complete formal implementation and staff training on the WFA-E model to develop proficient model users and implement use of the WRRM and FPI in evaluating wildfire risks including vegetation ignition likelihood.

B.2.11 Contact by Object Ignition Likelihood (LO)

High-level bow tie schematic



High-level calculation procedure schematic



High-level narrative

BVES collaborated with DIREXYON to introduce a new risk modeling tool to BVES's wildfire risk mitigation practices. The model is completed; however, as of the date of this filing the model is not fully implemented. BVES staff are completing training by DIREXYON on the model and BVES will need to set certain modifier values and risk weightings before the model is fully operational. BVES expects the model to be in full operation by Q4 2024. Updates to Appendix B including the addition of the DIREXYON's White Paper have been made as part of BVES Risk Modeling updates. The following paragraphs describe the new risk model.

- *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*

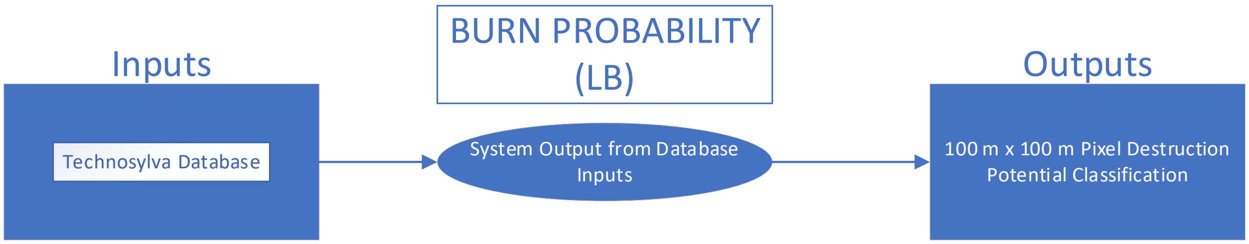
As the model is still in development BVES is not yet aware how the output will be characterized and presented to decision makers. Following the completion of the development phase BVES will have a better understanding of the output and how it can be used by decision makers in the wildfire mitigation process.

- *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.*

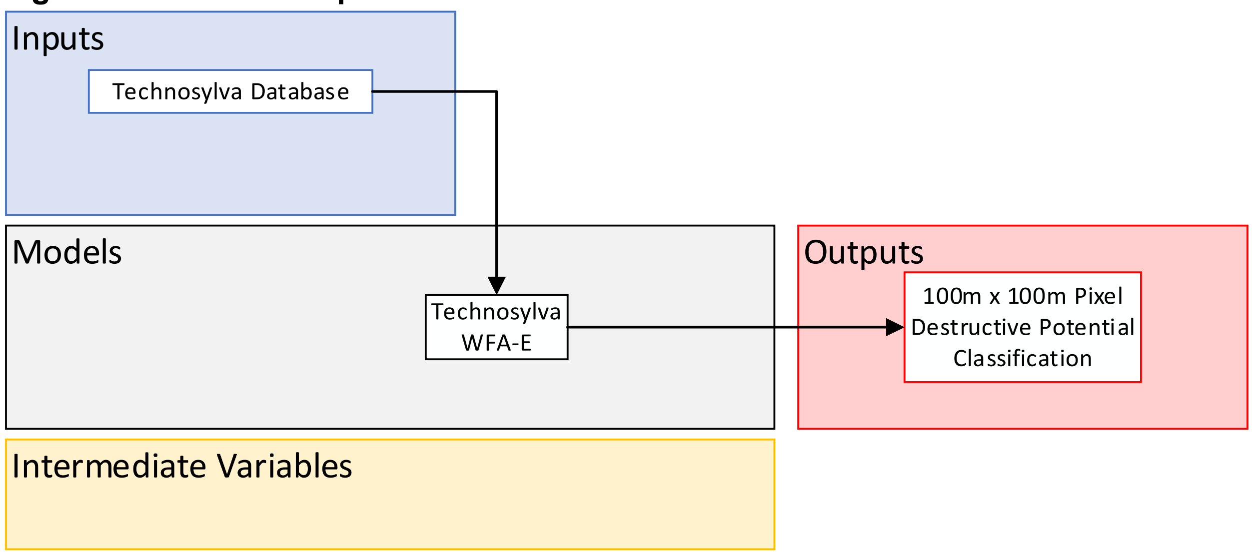
BVES will review feedback from the working groups that it has been involved in including the Wildfire Risk Model Working Group and assess the need for improvements or changes. BVES plans to include more data and documentation for this risk model/component in future WMPs. Additionally, BVES plans to complete formal implementation and staff training on the WFA-E model to develop proficient model users and implement use of the WRRM and FPI in evaluating wildfire risks including contact by object ignition likelihood.

B.2.12Burn Probability (LB)

High-level bow tie schematic



High-level calculation procedure schematic



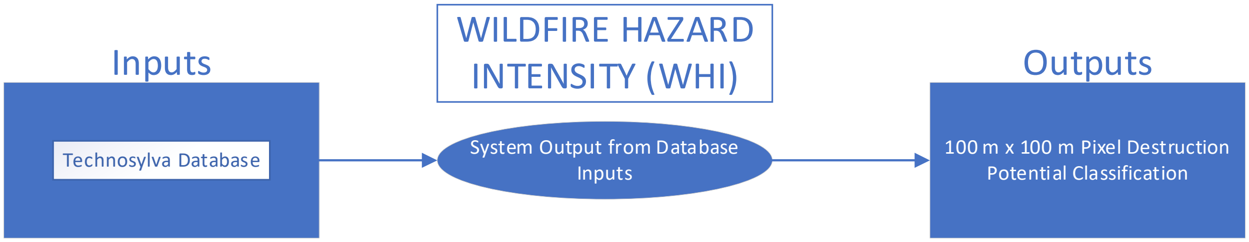
High-level narrative

- *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, 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.*

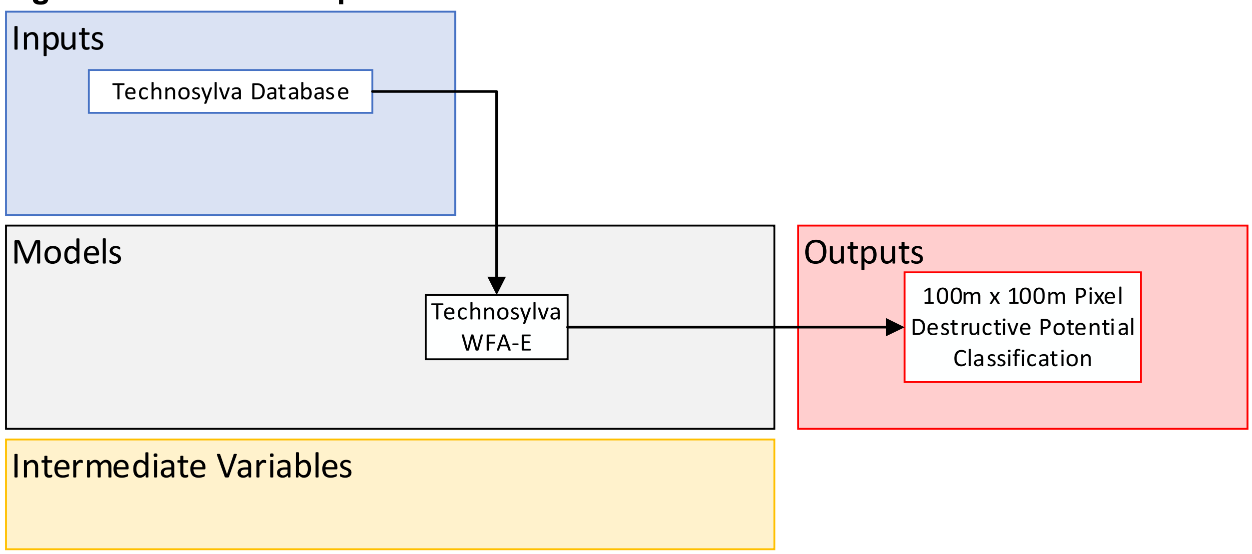
BVES will review feedback from the working groups that it has been involved in including the Wildfire Risk Model Working Group and assess the need for improvements or changes. BVES plans to include more data and documentation for this risk model/component in future WMPs. Additionally, BVES plans to complete formal implementation and staff training on the WFA-E model to develop proficient model users and implement use of the WRRM and FPI in evaluating wildfire risks including burn probability.

B.2.13 Wildfire Hazard Intensity (WHI)

High-level bow tie schematic



High-level calculation procedure schematic



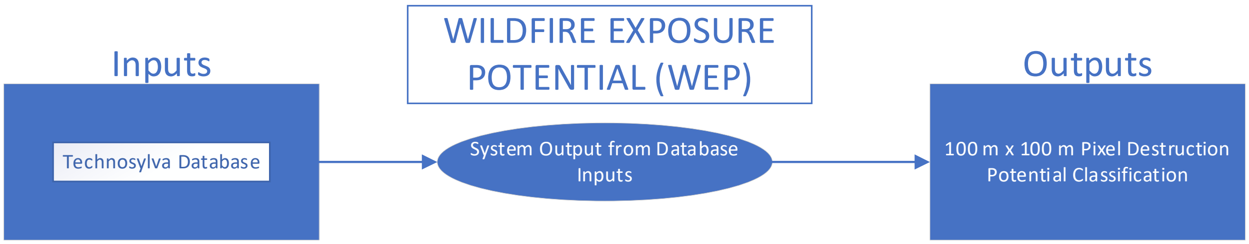
High-level narrative

- *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, 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.*

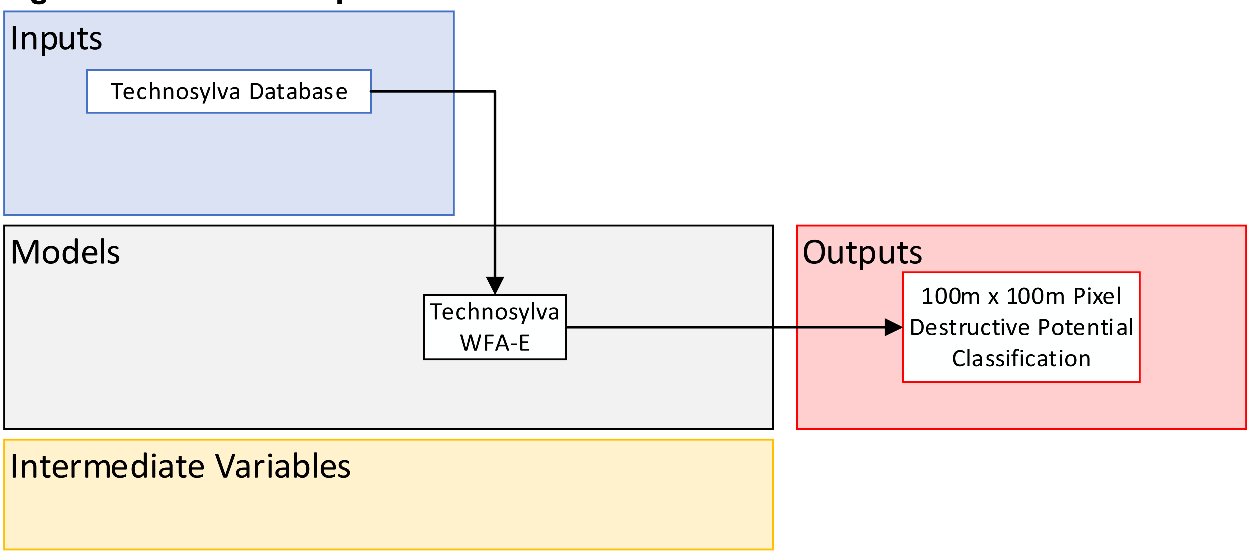
BVES will review feedback from the working groups that it has been involved in including the Wildfire Risk Model Working Group and assess the need for improvements or changes. BVES plans to include more data and documentation for this risk model/component in future WMPs. Additionally, BVES plans to complete formal implementation and staff training on the WFA-E model to develop proficient model users and implement use of the WRRM and FPI in evaluating wildfire risks including wildfire hazard intensity.

B.2.14Wildfire Exposure Potential (WEP)

High-level bow tie schematic



High-level calculation procedure schematic



High-level narrative

- *Purpose of the calculation/model*

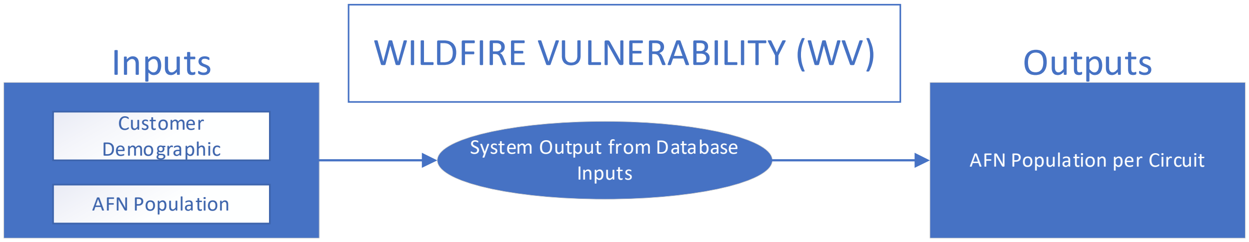
The purpose of the model is to provide a visual tool that displays the physical, social, and economic impact of a wildfire on the people property, critical infrastructure, livelihoods, health, environmental services, local economies, cultural/historical resources, and other high-value assets. These may include direct or indirect impacts, as well as short- and long-term impacts.

- *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, 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.*

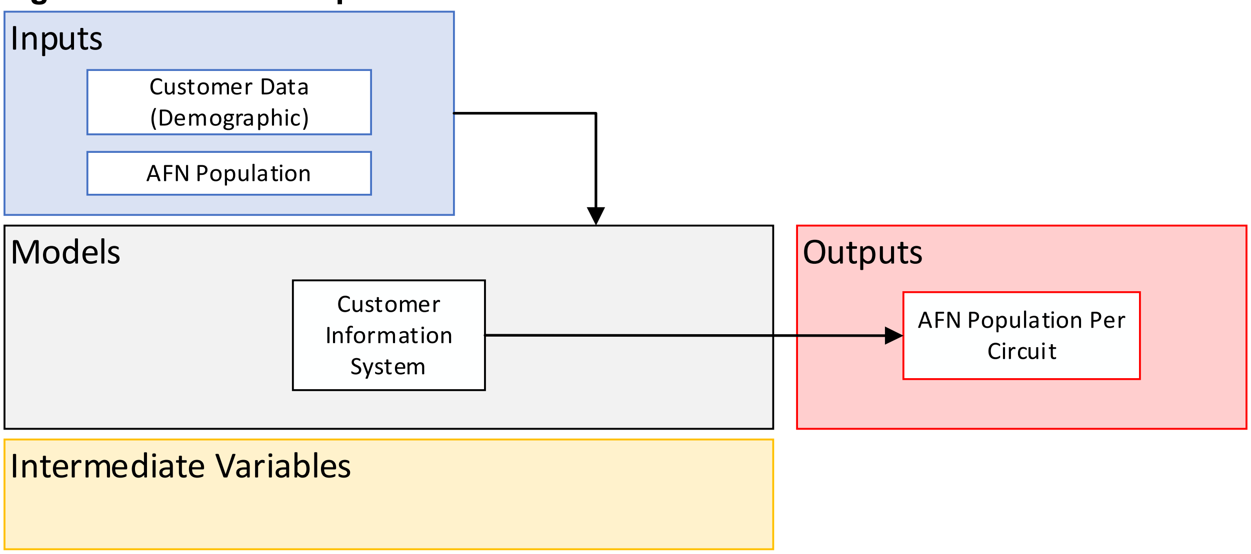
BVES will review feedback from the working groups that it has been involved in including the Wildfire Risk Model Working Group and assess the need for improvements or changes. BVES plans to include more data and documentation for this risk model/component in future WMPs. Additionally, BVES plans to complete formal implementation and staff training on the WFA-E model to develop proficient model users and implement use of the WRRM and FPI in evaluating wildfire risks including wildfire exposure potential.

B.2.15Wildfire Vulnerability (WV)

High-level bow tie schematic



High-level calculation procedure schematic



High-level narrative

- *Purpose of the calculation/model*

The purpose of this calculation is to determine the AFN population per circuit which will be used as an input in determining the Wildfire Risk for a circuit segment.

- *Assumptions and limitations*

The assumption or limitation of this risk component is that the evaluation process assumes all AFN customers have registered themselves with BVES. It is highly likely that there are customers that would fall in the AFN category that BVES is not aware of due to the need for customer action.

- *Description of the calculation procedure shown in the bow tie and high-level schematics*

BVES will evaluate the customer data and the AFN population data that is available in the Customer Information System to determine the number of AFN customers per circuit.

- *Description of how outputs will be characterized and presented (e.g., visualization) to decision makers*

The output from Wildfire Vulnerability will be a customer's/circuit unit that will be used as a sub-component for Wildfire Risk. While the output metrics will be visible to decision makers it will primarily be used in determination of Wildfire Risk.

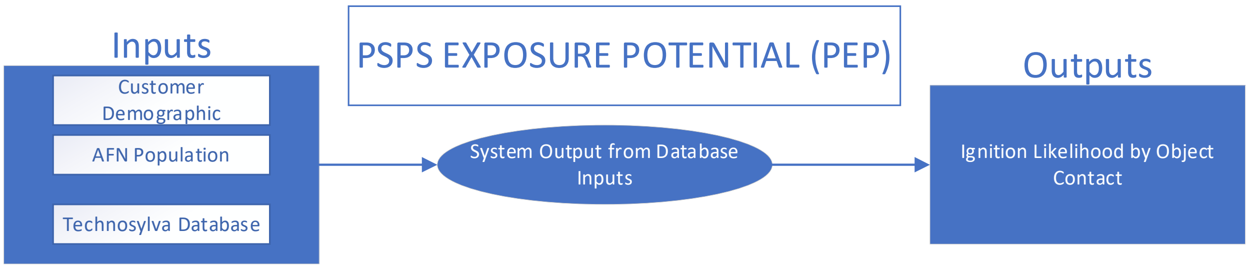
- *Concise description and timeline of planned changes to the calculation procedure over the triennial WMP cycle, including any key improvements from the Energy*

Safety Wildfire Risk Modeling Working Group and plans to align with the consensus Risk Modeling Requirements by January 1, 2024.

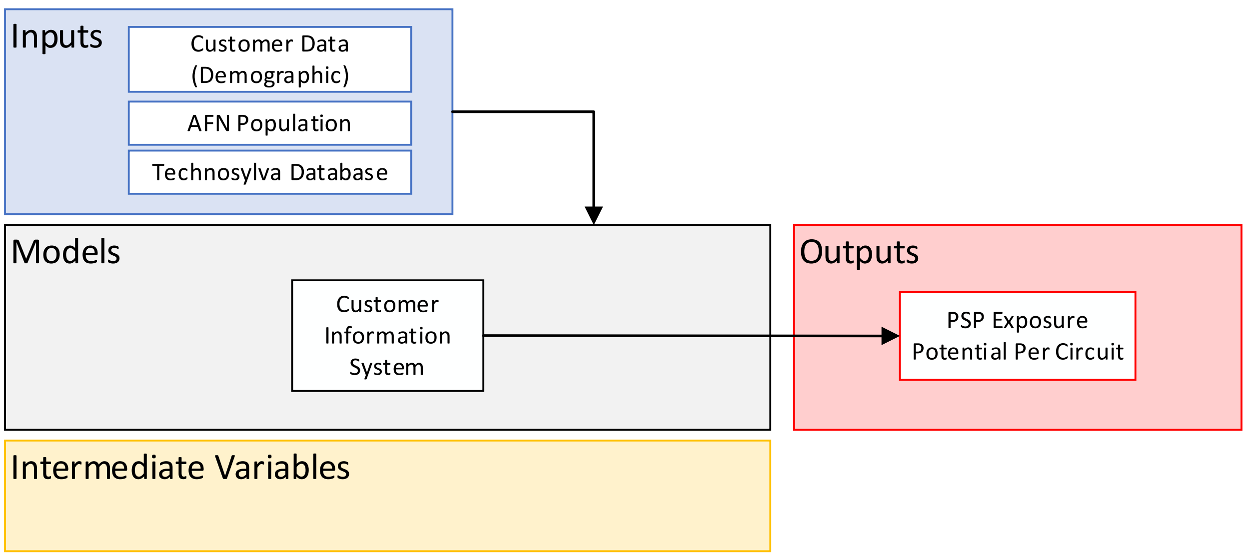
BVES will review feedback from the working groups that it has been involved in including the Wildfire Risk Model Working Group and assess the need for improvements or changes. BVES plans to include more data and documentation for this risk model/component in future WMPs. Additionally, BVES plans to complete formal implementation and staff training on the WFA-E model to develop proficient model users and implement use of the WRRM and FPI in evaluating wildfire risks including wildfire vulnerability of BVES system and customers.

B.2.16PSPS Exposure Potential (PEP)

High-level bow tie schematic



High-level calculation procedure schematic



High-level narrative

BVES collaborated with DIREXYON to introduce a new risk modeling tool to BVES's wildfire risk mitigation practices. The model is completed; however, as of the date of this filing the model is not fully implemented. BVES staff are completing training by DIREXYON on the model and BVES will need to set certain modifier values and risk weightings before the model is fully operational. BVES expects the model to be in full operation by Q4 2024. Updates to Appendix B including the addition of the DIREXYON's White Paper have been made as part of BVES Risk Modeling updates. The following paragraphs describe the new risk model.

- *Purpose of the calculation/model*

The purpose of this calculation is to determine exposure potential for AFN customers if/when a PSPS event occurs. This model takes into account PSPS Vulnerability (PV)

- *Assumptions and limitations*

The assumption or limitation of this risk component is that the evaluation process assumes all AFN customers have registered themselves with BVES. It is highly likely that there are customers that would fall in the AFN category that BVES is not aware of due to the need for customer action. There also may be additional limitations associated with database update cycles, but that has not yet been determined

- *Description of the calculation procedure shown in the bow tie and high-level schematics*

The bow tie model and high-level schematic are representative of what BVES believes the process will look like. Following the completion of the development phase an accurate model can be made available.

- *Description of how outputs will be characterized and presented (e.g., visualization) to decision makers*

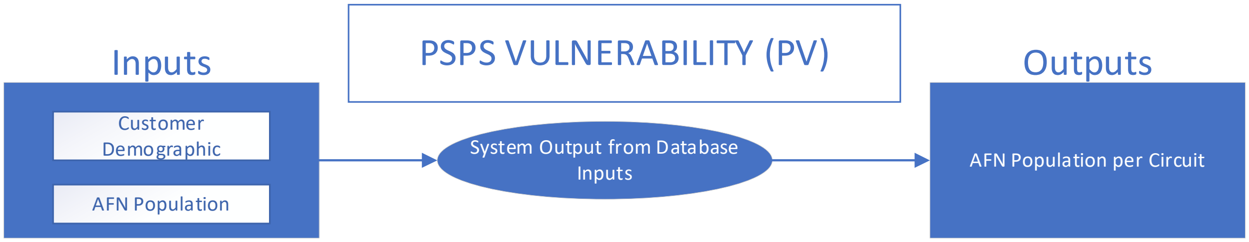
As the model is still in development BVES is not yet aware how the output will be characterized and presented to decision makers. Following the completion of the development phase BVES will have a better understanding of the output and how it can be used by decision makers in the wildfire mitigation process.

- *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.*

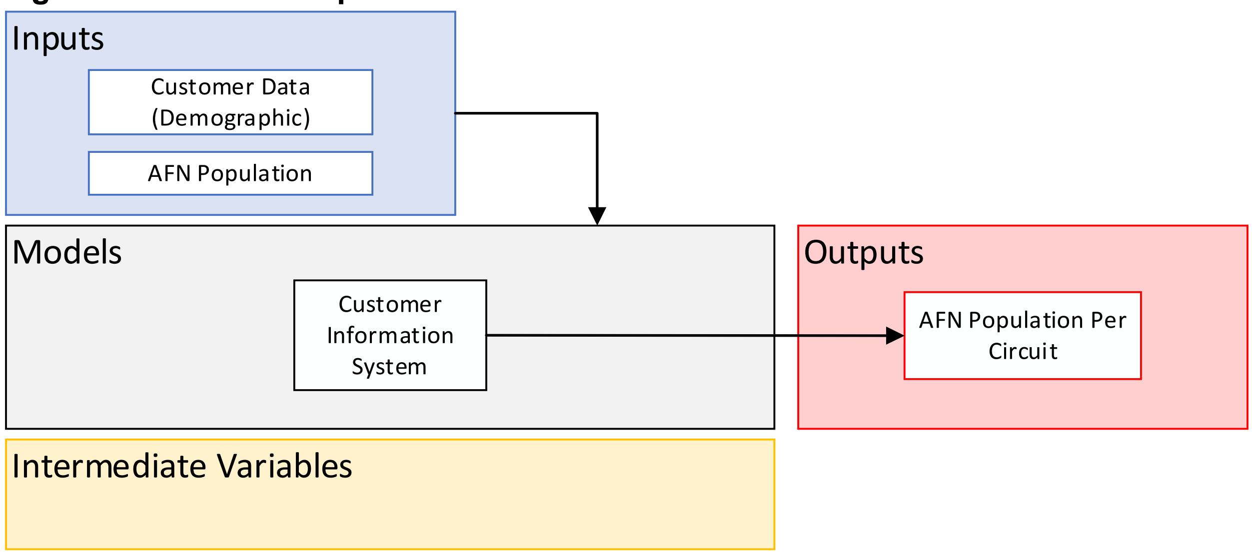
BVES will review feedback from the working groups that it has been involved in including the Wildfire Risk Model Working Group and assess the need for improvements or changes. BVES plans to include more data and documentation for this risk model/component in future WMPs. Additionally, BVES plans to complete formal implementation and staff training on the WFA-E model to develop proficient model users and implement use of the WRRM and FPI in evaluating wildfire risks including wildfire vulnerability of BVES system and customers.

B.2.17 PSPS Vulnerability (PV)

High-level bow tie schematic



High-level calculation procedure schematic



High-level narrative

- *Purpose of the calculation/model*

The purpose of this calculation is to determine the AFN population per circuit which will be used as an input in determining the PSPS Risk for a circuit segment.

- *Assumptions and limitations*

The assumption or limitation of this risk component is that the evaluation process assumes all AFN customers have registered themselves with BVES. It is highly likely that there are customers that would fall in the AFN category that BVES is not aware of due to the need for customer action.

- *Description of the calculation procedure shown in the bow tie and high-level schematics*

BVES will evaluate the customer data and the AFN population data that is available in the Customer Information System to determine the number of AFN customers per circuit.

- *Description of how outputs will be characterized and presented (e.g., visualization) to decision makers*

The output from PSPS Vulnerability will be a customer's/circuit unit that will be used as a sub-component for PSPS Risk. While the output metrics will be visible to decision makers it will primarily be used in determination of PSPS Risk

- *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.

BVES will review feedback from the working groups that it has been involved in including the Wildfire Risk Model Working Group and assess the need for improvements or changes. BVES plans to include more data and documentation for this risk model/component in future WMPs. Additionally, BVES plans to complete formal implementation and staff training on the WFA-E model to develop proficient model users and implement use of the WRRM and FPI in evaluating wildfire risks including PSPS vulnerability of BVES system and customers.

B.3 Detailed Model Documentation

Documentation for the DIREXYON models Phase 1 and Phase 2 is provided below.

Since the DIREXYON program was not used to develop this WMP, model substantiation is not included.

The Technosylva model documentation information is provided below.

DIREXYON

Bear Valley Electric Service

Phase 1 – Implementation of DIREXYON Suite for distribution assets
Preliminary Report

March 14, 2024

Contents

Executive Summary

The DIREXYON Solution specializes in advanced financial modelling and integrated decision support systems, leveraging artificial intelligence to aid asset-intensive industries in capital planning and strategic objectives. DIREXYON has offered asset management, risk management, and financial modelling solutions for over 21 years and is committed to providing end-to-end solutions to its customers. Asset managers, financial officers, project managers, and key decision-makers are provided with asset management capabilities as well as long-term forecasts of possible interventions and investment scenarios through advanced, combinatorial simulation techniques.

Investment scenarios generated by DIREXYON ensure sound resource management, optimized decision-making, and an understanding of risk's impact on desired results. And the volume at which DIREXYON can generate and process risk-return scenarios is a key differentiator within the asset investment planning space.

DIREXYON's expertise has empowered numerous organizations to lead in risk management and financial optimization. Thanks to the team's diverse expertise in asset management, finance, accounting, IT, modeling, and mathematics, these multidisciplinary strengths foster integration of innovative ideas in IT systems and their application to financial, asset, and risk management fields. With a trusted, international track record, DIREXYON has assisted asset management and capital investments in various sectors, including infrastructure, financial institutions, and power utilities.

Leveraging the use of the DIREXYON Solution, this project is dedicated to developing an advanced fire risk model that seeks to bridge critical gaps in BVES's risk modeling capabilities, as outlined in Section 6.2.2 of the 2023 Wildfire Mitigation Plan (WMP). Our focus is on integrating decision-making policies within existing constraints, emphasizing a comprehensive evaluation of the network's conditions. The key areas identified for enhancement are as follow:

1. Equipment ignition likelihood;
2. Contact from vegetation ignition likelihood;
3. Contact by object ignition likelihood;
4. Wildfire spread likelihood;
5. Wildfire hazard intensity;
6. Wildfire exposure potential
7. Wildfire vulnerability
8. PSPS exposure potential
9. Vulnerability of community to PSPS

The figure below provides a high-level schematic of the inputs, the modeling components as well as the outputs and insights generated as part of the first phase of the implementation of DIREXYON for Bear Valley Electric Service's distribution assets.

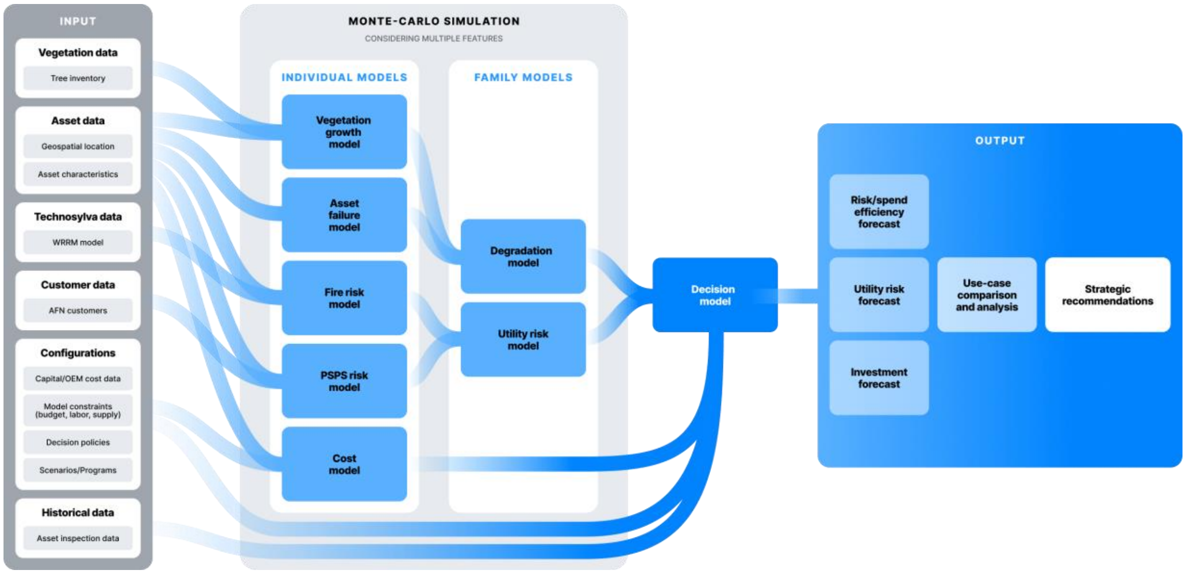


Figure 1 : DIREXYON Phase 1 Schematic for BVES Fire Risk Assessment

Fire risk and PSPS components of the model constitute the core of the model. The fire risk assessment integrates multiple factors, including asset related characteristics, equipment ignition, and vegetation contact. Simultaneously, the PSPS risk assessment considers wildfire spread, hazard intensity, exposure potential and community vulnerability, providing a comprehensive overview of the network's resilience to both fire-related incidents and PSPS events. Three distinct use cases have been outlined to offer comprehensive insights into the necessary investment levels to meet regulatory minimums, ascertain the current state of affairs, assess the short-term and long-term impacts of the existing BVES strategy on network conditions, and explore alternative fire mitigation strategies. Within each use case, we consider three weather trends, categorized as optimistic, normal, and pessimistic, based on varying Technosylva percentiles.

Dealing with various uncertainties in real-world scenarios, relying solely on deterministic approaches for predicting asset behavior seems impractical. Deterministic methods claim to pinpoint the exact time of asset failure, which may not align with the inherent unpredictability of real-world situations, where assets can fail before or after the predicted timeframe. Similarly, cost estimation introduces another layer of uncertainty. In contrast, Monte Carlo simulations represent stochastic approaches capable of forecasting the probabilities associated with multiple potential outcomes for assets. At DIREXYON, our utilization of Monte-Carlo simulations involves calculating a vast array of potential scenarios for asset degradation, cost uncertainties, and other variables, offering a more realistic and robust perspective on the range of possible outcomes.

This approach ensures a thorough examination of scenarios under different climatic conditions, enhancing the robustness of the analysis.

In conclusion, this project in the first phase seeks to rectify identified gaps within Bear Valley's 2023 Wildfire Mitigation Plan (WMP) while furnishing users with a tool for testing and appraising diverse fire mitigation strategies.

The results of this analysis indicates that The BVES Strategy's investment approach (use case 2), focusing on more than just meeting the GO165 minimum requirements (use case 1), demonstrates substantial long-term value by consistently maintaining fire risks at lower levels. By incorporating a variety of mitigation measures such as extensive vegetation management, fire wrap installations, and the proactive replacement of conductors, the strategy realizes a lower and more stable fire risk. This suggests that a relatively higher initial outlay for comprehensive fire risk mitigation measures can provide significant sustained benefits. The long-term payoff of this approach is clear when compared to Use Case 3, where the strategic choice to replace wood poles with more durable steel poles implies high upfront costs but promises greater savings over time due to reduced maintenance and replacement needs.

When making strategic decisions, stakeholders must weigh the benefits of upfront investments against long-term operational savings and the overarching goal of risk management. Use Case 3 offers an intriguing balance by potentially reducing the need for future interventions, which could be especially compelling given its implications for risk reduction and enhanced network resilience. As infrastructure ages, the investment strategies behind these use cases are crucial, with the proactive and preventative measures of Use Cases 2 and 3 likely resulting in lower average infrastructure ages and correspondingly lower costs and risks in the long run. The executive choice ultimately depends on the desired balance between managing immediate costs, ensuring long-term savings, and achieving a resilient, reliable power supply for all customers, including the most vulnerable who rely on consistent electricity access.

The outcomes empower decision-makers with a comprehensive understanding of network conditions, enabling proactive risk management and informed decision-making for a more resilient and secure energy infrastructure.

Solution Methodology

The DIREXYON Solution enables program design activities. Program design requires the combination of all three core capabilities, i.e. asset forecasting, decision-making and portfolio management, and can be viewed as the end result of the approach. The DIREXYON Solution encompasses a powerful asset modelling tool where an unlimited number of models could be configured by simple "drag and drop". Its simplicity allows users to model their asset portfolio without the need for programming. First, sophisticated asset evolution and condition models, risk models, level of services, KPIs and any other relevant indicators can be configured. Then, an unlimited number of intervention options as well as their costs and impacts can be defined. Finally, realistic scenarios can be built by simple configuration of user-defined constraints.

In addition, the DIREXYON Solution is designed to enable the organization to formalize the internal decision-making processes that are driving asset management planning strategies. The entire decision-making process can be realistically modeled using decision trees that are then used to perform a combinatorial analysis. A decision tree represents a series of decisions, and the criteria used, leading to the application of an intervention choice. The criteria can be related to the condition of the assets, the use of the assets, the degradation of the assets, the different risks, constraints, standards, etc. Decision trees also allow to manage unforeseen events, such as equipment failures or defects. The scenario and optimization module of the platform can be used to configure and launch several Monte-Carlo simulations (scenarios), simultaneously when needed, to compare several strategies. This approach allows the evaluation of conditional scenarios (what-if scenarios), sensitivity analysis and the evaluation of the impact of constraints on the ability to deliver programs.

Considering the stochastic nature of asset evolution is a key component of an advanced asset management methodology, the DIREXYON Solution provides a global perspective of the risk associated with the tested strategies. The user is also able to evaluate the impact of the actions undertaken on the probability of achieving the targeted objectives. The decision-making acuity provided by the DIREXYON Solution allows decision-makers to evaluate these options according to their risk tolerance.

Program Building

The DIREXYON Solution provides the ability to build user-defined specific programs for any asset class and for any type of investment (inspection, maintenance, replacement, etc.) by using decision trees. These programs can be conditioned on any relevant attributes (e.g. location, model, load, circuit, material, etc.) or constraint. Forecasting the entire portfolio of assets in the long-term allows the ability to identify investment opportunities and build relevant programs to address the short, medium, and long-term needs.

As an example, users could easily configure a Wood Pole Replacement Program, triggered by pole material (Material = Wood). Program specifications could then be assessed more precisely through the configuration of a Pole Replacement Program intervention using the modelling tool. For example, one could seek a program where wood poles over a certain age in high fire risk circuits are prioritized to be replaced by steel poles.

Program Scheduling

A key feature of the DIREXYON Solution is the ability to forecast its whole portfolio of assets over time to get a better understanding of the evolution of the condition of the network and forecast needs for capital investment. This forecast is crucial to program scheduling. As such, asset evolution over time will be computed by applying degradation and condition models configured in the modelling tool. Then, for each year considered in the simulation, each asset and/or group of assets will be exposed to user-defined decision trees. The simulation time scale can be user defined, depending on the client's required granularity for program planning (months, quarters, years). This combinatorial approach, where a set of user-defined criteria leads to a specific intervention, dynamically triggers interventions when asset condition or applicable constraints are reached. Interventions can be bundled into programs.

As programs will be triggered at the right location, at the right time, and for the right assets and/or groups of assets, program scheduling is then automatically performed through the simulation process. Users can test a variety of program parameters, by simulating scenarios (predictions) with different trigger levels, constraints and/or program specifications. Using the optimization toolkit, clients can optimize scheduling by setting up an objective function under a defined set of constraints (e.g. minimize costs while keeping an average circuit-level fire risk below a certain threshold).

Program Ordering, Receiving, Distribution and Installing

Using the decision tool, users can configure decision-trees to model a decision process based on client-specific business rules for ordering, receiving, distribution and installing interventions and trigger those based on user-defined criteria.

As mentioned in the previous section, the simulation time scale is user-defined. For example, program building, and scheduling can be performed on an annual basis over the long-term to forecast needs and find the most profitable strategies from an entire asset portfolio lifecycle perspective. Then, program shaping could be done monthly over a shorter period. This flexibility offered by the platform allows for optimization of performance by selecting the right time scale and simulation duration based on scenario objectives.

Project Methodology

From a modeling standpoint, DIREXYON has organized assets hierarchically, wherein each asset type comprises multiple individual assets, each with its dedicated risk, degradation, and decision model.

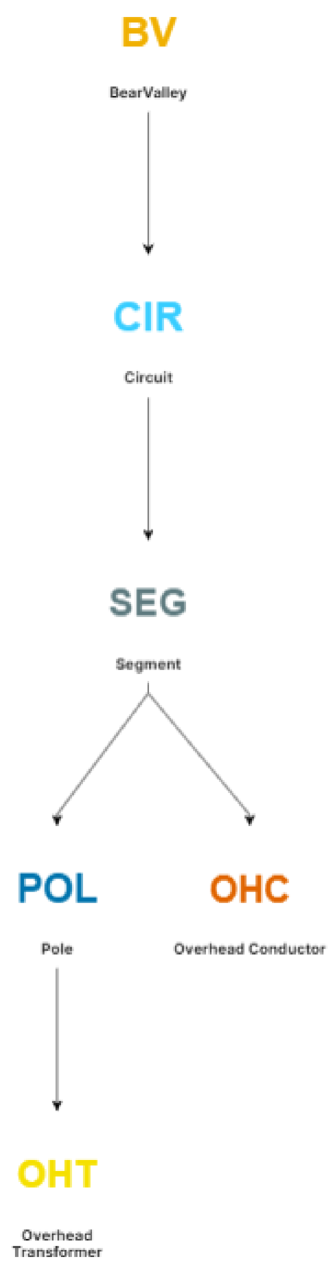
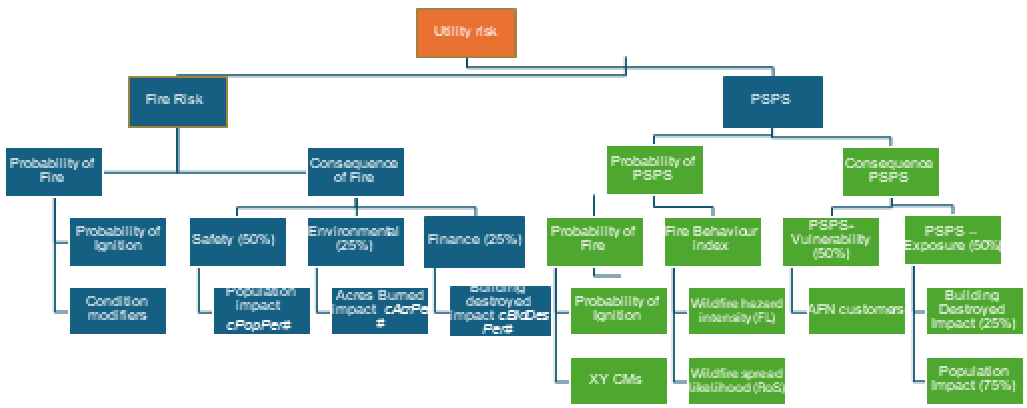


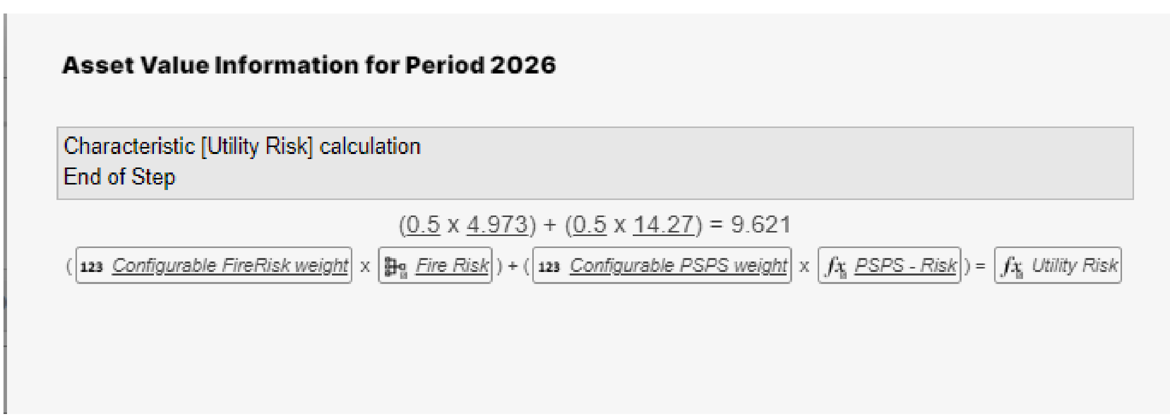
Figure 2 : Overview of Asset Hiearchy in DIREXYON

At the heart of this model lies the concept of risk, embodying adverse events, specifically fires and PSPS incidents in this context. The current approach calculates risk by multiplying the probability of these adverse events by their potential consequences. Put simply, probability reflects the likelihood of these events happening, while consequence details the potential impact if the event does occur. The following chart summarizes the risk model:



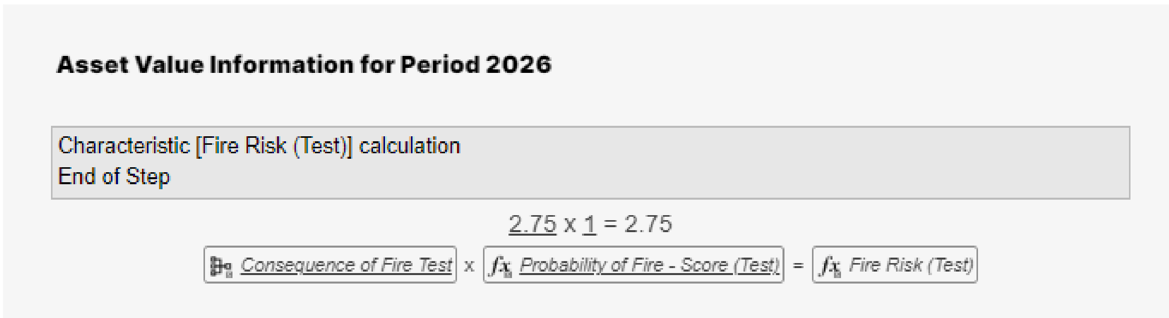
Utility Risk

Utility risk is encapsulated by the average **fire risk at the individual asset level** and the calculated **PSPS risk at the circuit level**. While subject matter experts initially allocate a 50% weight to each component, this weighting is **configurable** and can be easily adjusted during the simulation process. The attached screenshot represents the utility risk calculations in the circuit level.



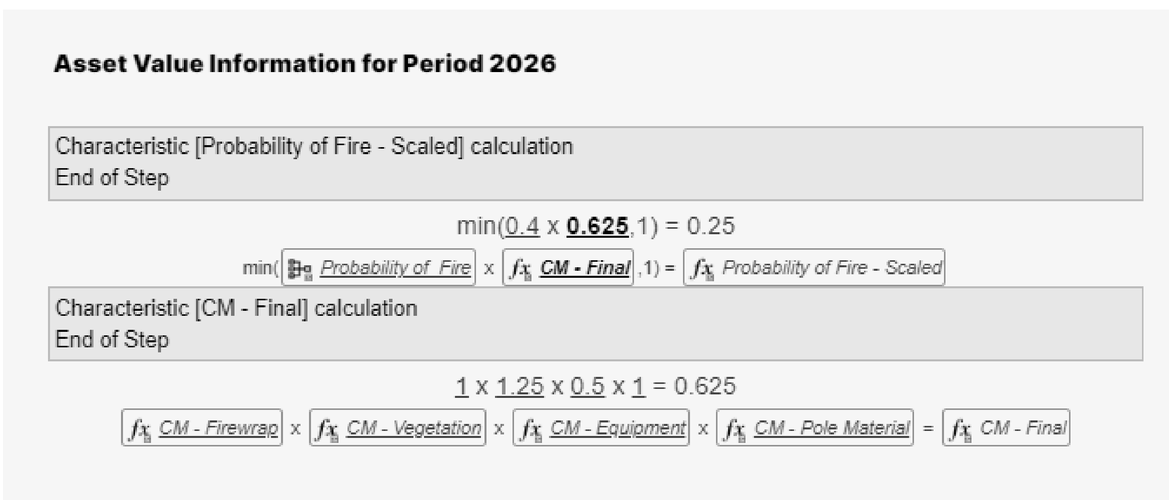
Fire Risk

The DIREXYON Solution computes **fire risk at the individual asset level**, and the cumulative risk at each level contributes to the overall fire risk assessment of the entire network. Each individual asset type's fire risk comprises two components: **probability of fire and consequence of fire**, explained below:



Probability of Fire

The probability of fire gauges the likelihood of fire ignition specific to each asset type. It is calculated as the product of the Technosylva-calculated Probability of Ignition (POI) and XY condition modifiers (CMs). The attached screenshot represents the probability of fire risk calculations along with overall CM calculations for poles.



XY Condition modifiers

Condition modifiers in the model are to show the impact of asset characteristics and specific interventions on the calculated probability of fire by Technosylva. For example, if a bare conductor is replaced with a covered conductor, what is the impact on risk mitigation? Accordingly, the following condition modifiers are defined in individual asset levels as detailed below:

Conductor Condition Modifiers

Conductor Material

This modifier assesses the effect of conductor material (such as copper or other materials) on overall fire risk. Notably, copper conductors are associated with a higher probability of igniting a fire. Consequently, substituting copper conductors with non-copper materials reduces the fire risk by 50%, while the reverse—replacing non-copper materials with copper—increases the risk by 50%. Please note that, the 50% values are a placeholder in the model that needs to be adjusted with more insights from subject matter experts.

This nuanced approach enables users to quantify the potential risk mitigation or escalation associated with changes in conductor types.

Conductor Type

This condition modifier delineates the effects of various conductor types, specifically comparing covered and uncovered variants. Transitioning from uncovered to covered conductors notably diminishes the associated fire risk. Consequently, implementing coverings on previously non-covered conductors results in a 50% reduction in fire risk. Please note that this value is taken from available literature (1- 4) and serves as a placeholder in the model, and with further insight from the client and access to historical events correlated with conductor types, adjustments can be made for a more accurate assessment.

Accordingly, the conductor probability of fire is the product of Technosylva-calculated Probability of Ignition (POI), CM – Conductor Material, and CM – Conductor type.

These two condition modifiers specifically address the Equipment Ignition Likelihood within the identified gap.

Transformer Condition Modifiers

Transformer failure

This condition modifier encapsulates the impact of transformer degradation on the probability of fire. Transformer degradation is characterized by age and different Kva ratings. Additionally, an asset-specific accidental failure probability of 0.002 is incorporated into the risk/failure model. In the absence of historical failure data from BVES, the accidental failure probability of 0.002 serves as a placeholder, derived from the findings of a study by S. Tenbohlen (2011)(5).

The current condition modifier for transformers is derived from a Weibull failure curve, considering transformer age, Kva, and accidental failure probability. Specifically, for a brand-new transformer or pole, the condition modifier (CM) is 1. As transformers age, the CM exponentially increases from 1 to 2.

The 0.2% probability of accidental failure for transformers addresses the Contact by Object Ignition Likelihood within the identified gap.

This data provides valuable insights into the potential risks associated with transformer conditions.

Pole Condition Modifiers

Fire Wrap

This condition modifier assesses the impact of installing fire wraps on wooden poles as a risk mitigation measure. Accordingly, the installation of fire wraps on wooden poles initially without them can result in a 10% reduction in fire risk. Please note that this value serves as a placeholder in the model that is confirmed by subject matter experts, and with further insight from the client, adjustments can be made for a more accurate assessment.

Pole material

This condition modifier evaluates the impact of pole material on fire risk, with wooden poles generally posing a higher risk of ignition compared to metal poles. The modifier facilitates an understanding of the potential risk reduction by replacing wooden poles with steel in the network. Currently, replacing wood material with non-wood reduces the fire risk by 10%. Please note that this value serves as a placeholder in the model that is also confirmed by subject matter experts, and with further insight from the client, adjustments can be made for a more accurate assessment.

Vegetation

Vegetation is incorporated into the model as an integral part of the pole asset type. The likelihood of fire caused by vegetation varies based on the state of trees—whether they have fallen, grown, or the overall tree density (Fall in, Grow in, and Tree density). Markov chains are employed to model the probability of transitioning from the best zone (4) to the worst zone (1), dependent on the number of years since the last vegetation inspection.

For all three mentioned metrics, a zone value is predicted annually based on the elapsed time since the last vegetation management intervention. Consequently, with an increasing number of years since the last vegetation management intervention, the probability of transitioning from the best zones to the worst zones rises. In simpler terms, without regular inspections, there is a heightened risk of the vegetation around the equipment growing unchecked, thereby increasing the likelihood of fires.

The final CM vegetation is the product of three Condition Modifiers (CMs) CM – Fall in, CM – Grow in, and CM – Density. For each metric if the tree's state remains unaltered compared to the initial state, the related CM is set at 1. However, if it deteriorates, the CM adjusts from 25% to 100% (based on the initial and current zones), and if it improves, it decreases by 25% to 75%. This meticulous approach ensures a nuanced representation of the impact of vegetation on fire risk within the model. Please note that this value serves as a placeholder, and with further insight from the client and access to historical fall-in and grow-in data, adjustments can be made for a more accurate assessment. Each of the identified metrics is briefly explained below:

Grow-In

This metric relies on a shape file provided by the client, representing the likelihood of tree branches growing into power lines and causing fires. The clear_level in the data interprets the Grow-in values.

Fall-In

Data for this metric is sourced from a shape file provided by the client. Calculated based on tree height and the distance of the tree to the pole, Fall-In zones are defined depending on the minimum height required for a tree to impact an asset. This determination considers the pole height, tree distance to pole, and the specified minimum heights.

Density

Data for this metric comes from the VegManagementDataPartner, with no specific aggregation performed on the dataset. It represents the density of vegetation around the assets.

These condition modifiers address the contact from vegetation ignition likelihood within the identified gap.

Equipment

A pole linked to high-risk equipment, such as a transformer and/or conductor, inherently carries an elevated fire risk. This condition modifier encapsulates the cumulative effect of calculated Condition Modifiers (CMs) for transformers and conductors, providing a comprehensive assessment of the associated risk for a given pole.

Consequence of Fire

Consequence of fire values delineate the impact of fire on population, buildings destroyed, and acres burned. These values, determined by **Technosylva at the segment level**, remain constant across all asset types within same segment. The mentioned consequences are grouped into safety, environmental, and finance impact with **user-defined weights** that can be easily adjusted upon running the simulation. The attached screenshot represents the calculated consequence of fire in segment level based Technosylva data and configurable weights:

Asset Value Information for Period 2026

Characteristic [Consequence of Failure - Fire (Test)] calculation
End of Step

0.25 x 7 + 0.25 x 2 + 0.5 x 4 = 4.25

Acres Impact - Weight (WildFire) x Acres Impact- Score - Test + Destroyed Building Impact - Weight (WildFire) x Destroyed Building Impact - Score (Test) + Population Impact - Weight (WildFire) x Population Impact - Score (Test) = Consequence of Failure - Fire (Test)

PSPS Risk

The DIREXYON suite computes PSPS risk at the **circuit level**, and the cumulative risk at circuit level contributes to the overall utility risk of the network. Similar to the fire risk, PSPS risk comprises two components: probability of PSPS and consequence of PSPS, explained below:

Asset Value Information for Period 2026

Characteristic [PSPS - Risk] calculation
End of Step

3.114 x 4.583 = 14.27

PSPS - Consequences x PSPS - Probability Score = PSPS - Risk

PSPS Probability

In the absence of FPI data from Technosylva and based on the available literature by PG&E (6), PSPS probability is defined based on calculated fire probabilities in individual asset levels (POI*CMs) and fire behaviour index.

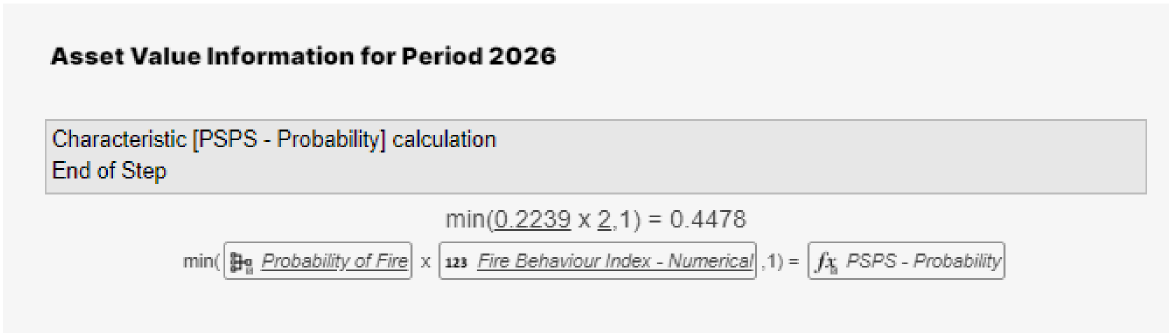


Fig. 1. High level overview of 2021 Distribution PSPS guidance

Fire behaviour classes (1-5) are defined in **segment level** based on two components of Technosylva that is Fire Rate of Spread, and Flame length as below:

FIRE BEHAVIOR CLASS			ros (ch/h) 100 ch/h = 1.25 mi/h					
			VERY LOW	LOW	MODERATE	HIGH	VERY HIGH	EXTREME
		0	0 - 2	2 - 5	5 - 20	20 - 50	50 - 150	>150
fl (ft)	VERY LOW	0 - 1	1	1	1	1	2	3
	LOW	1 - 4	1	1	2	2	3	4
	MODERATE	4 - 8	1	2	2	3	4	5
	HIGH	8 - 12	1	2	3	3	4	5
	VERY HIGH	12 - 25	2	3	3	4	5	5
	EXTREME	>25	3	3	4	4	5	5

PSPS Consequence

PSPS Consequence values outline the repercussions of Public Safety Power Shutoffs (PSPS) on distinct categories, including **vulnerable individuals (AFN customers)**, the general population, and affected buildings. These consequences are categorized into PSPS vulnerability and PSPS exposure, with customizable user-defined weights that can be easily adjusted upon running the simulation.

Asset Value Information for Period 2026

Characteristic [PSPS - Consequences] calculation
End of Step

(0.5 x 1) + (0.5 x **5.227**) = 3.114

(Configurable PSPS Vulnurability Consequence Weight x PSPS - Vulnerability) + (Configurable PSPS Exposure Consequence Weight x **PSPS - Exposure**) = PSPS - Consequences

Characteristic [PSPS - Exposure] calculation
End of Step

(0.25 x 5.863) + (0.75 x 5.016) = 5.227

(Building Destroyed Impact Configurable Weight (PSPS) x Building Destroyed Impact - Score) + (Population Impact Configurable Weight (PSPS) x Population Impact - Score) = PSPS - Exposure

Use Cases

Three distinct use cases are crafted to drive insights in this phase of analysis, aiming to elucidate the necessary investments for meeting regulatory minimums, understand the present state of the network, anticipate its short-term and long-term evolution under the existing Bear Valley strategy, and explore alternative mitigation approaches. The outlined use cases are as follows:

1. GO.165 Requirements:
    a. Focuses solely on meeting the minimum requirements stipulated by GO.165.
2. Current BVES Strategy:
    a. Satisfies the minimum requirements of GO.165 with added measures:
        i. Installation of fire wraps
        ii. Proactive replacement of bare conductors
        iii. Implementation of vegetation management strategies
3. Alternative Mitigation Strategy:
    a. Explores the consequences of replacing wooden poles with steel, as an alternative to fire wrap installation in the current BVES strategy.

These use cases aim to familiarize the client with the diverse analyses and insights achievable through the DIREXYON Solution. By exploring different scenarios, we highlight the Solution's versatility in risk assessment, strategy evaluation, and decision-making, providing a concise yet comprehensive overview of its capabilities. The following will outline the step-by-step journey of one asset for each of the pole, overhead conductor, and overhead transformer asset types throughout a model simulation for each of the use cases. Each use case is simulated over 60 years and 50 iterations.

GO.165 Requirements

Decision trees in the model reflect the maximum allowable inspection cycle lengths for poles, as described in the table below:

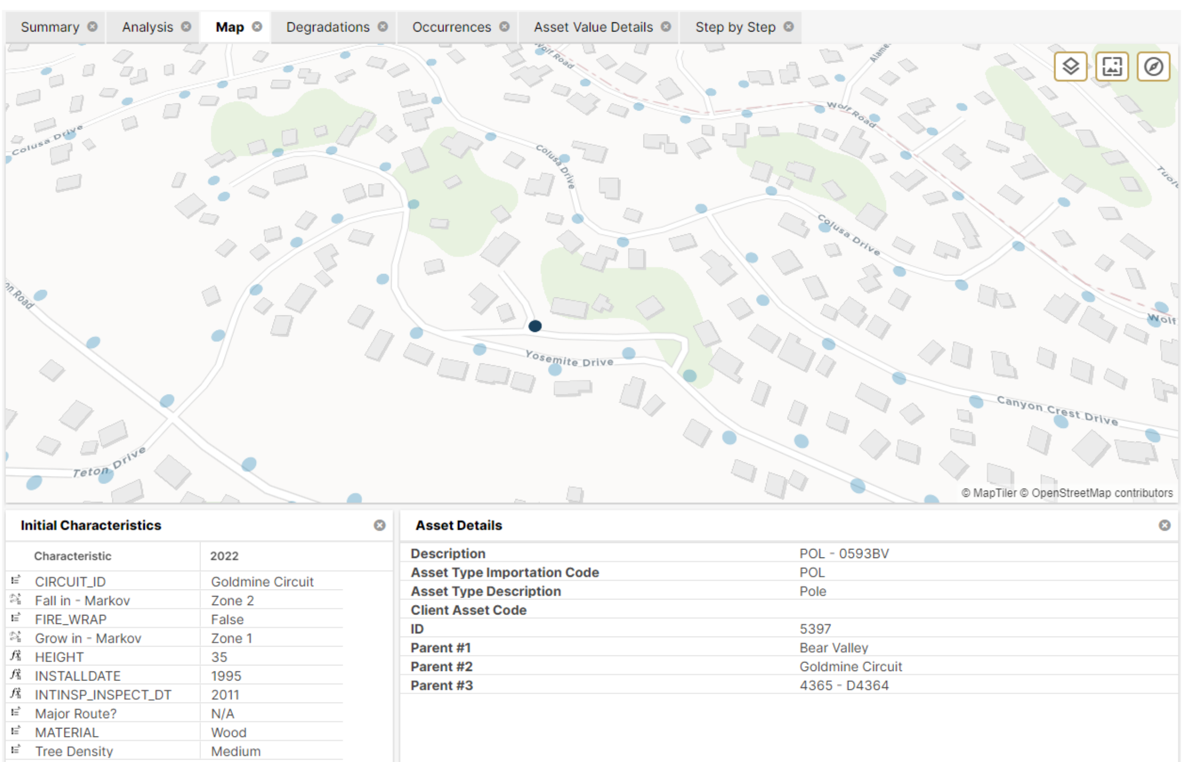
Table

	Patrol		Detailed		Intrusive	
	Urban	Rural	Urban	Rural	Urban	Rural
Transformers						
Overhead	1	2	5	5	---	---
Underground	1	2	3	3	---	---
Padmounted	1	2	5	5	---	---
Switching/Protective Devices						
Overhead	1	2	5	5	---	---
Underground	1	2	3	3	---	---
Padmounted	1	2	5	5	---	---
Regulators/Capacitors						
Overhead	1	2	5	5	---	---
Underground	1	2	3	3	---	---
Padmounted	1	2	5	5	---	---
Overhead Conductor and Cables	1	2	5	5	---	---
Streetlighting	1	2	x	x	---	---
Wood Poles under 15 years	1	2	x	x	---	---
Wood Poles over 15 years which have not been subject to intrusive inspection	1	2	x	x	10	10
Wood poles which passed intrusive inspection	---	---	---	---	20	20

Source: GO95_128_&165_Seminar.pdf (CPUC Utilities Safety and Reliability Branch)

Poles

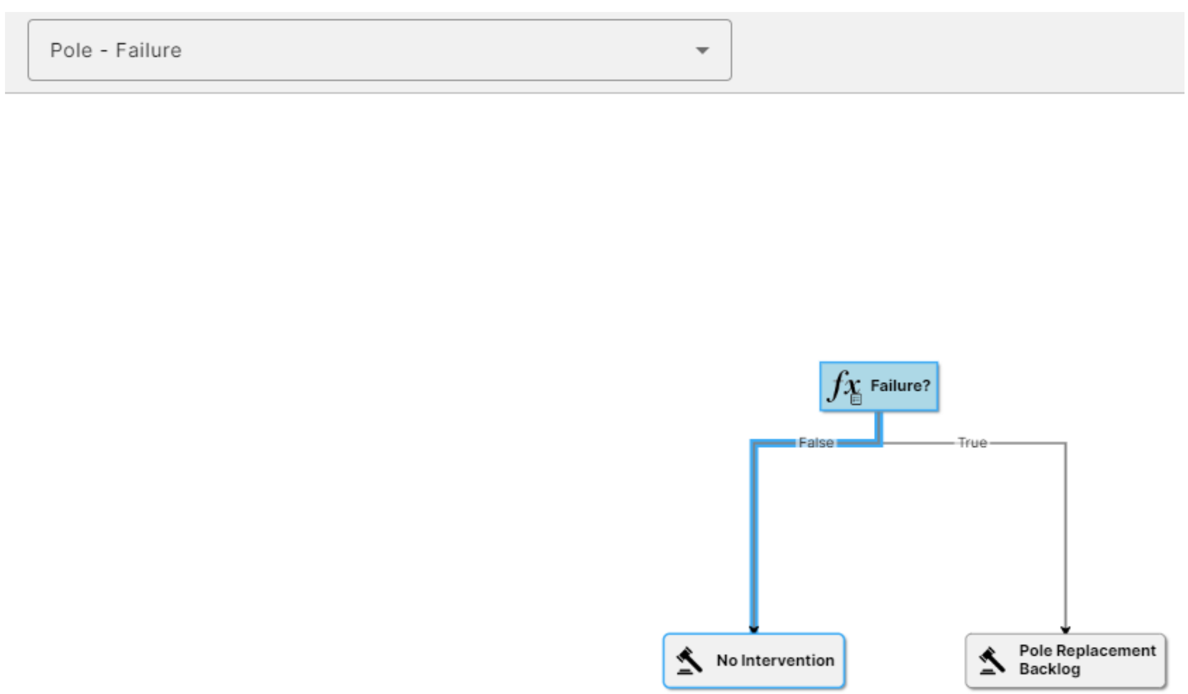
This use case will follow the step-by-step journey of Pole 0593BV of iteration 1 between the start of the simulation in 2023, to its replacement in 2027:



Degradation

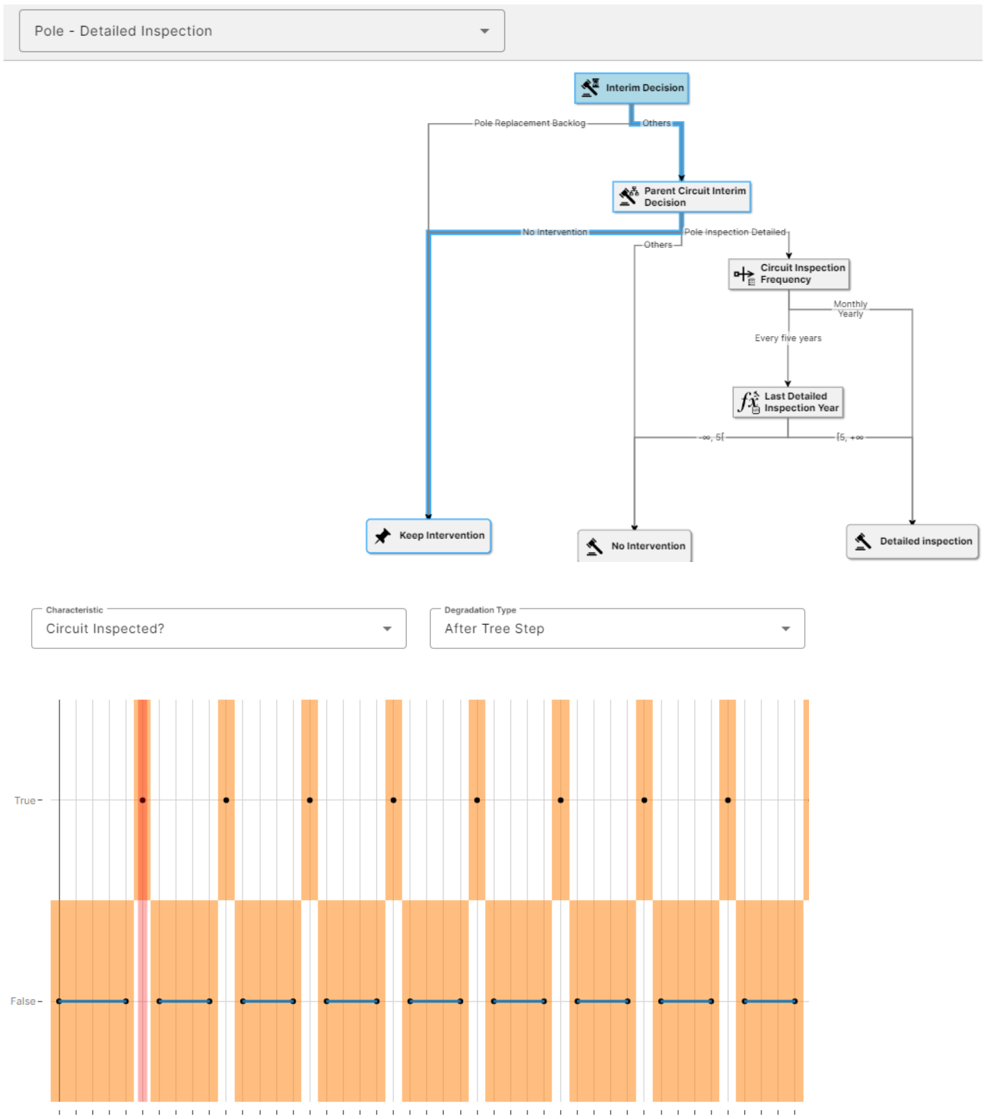
The pole is 28 years of age at the start of the simulation and ages by one year between 2023 and 2027.

Between 2023 and 2026, the model does not trigger a failure for this asset, as seen in the decision tree below:



Detailed Inspections

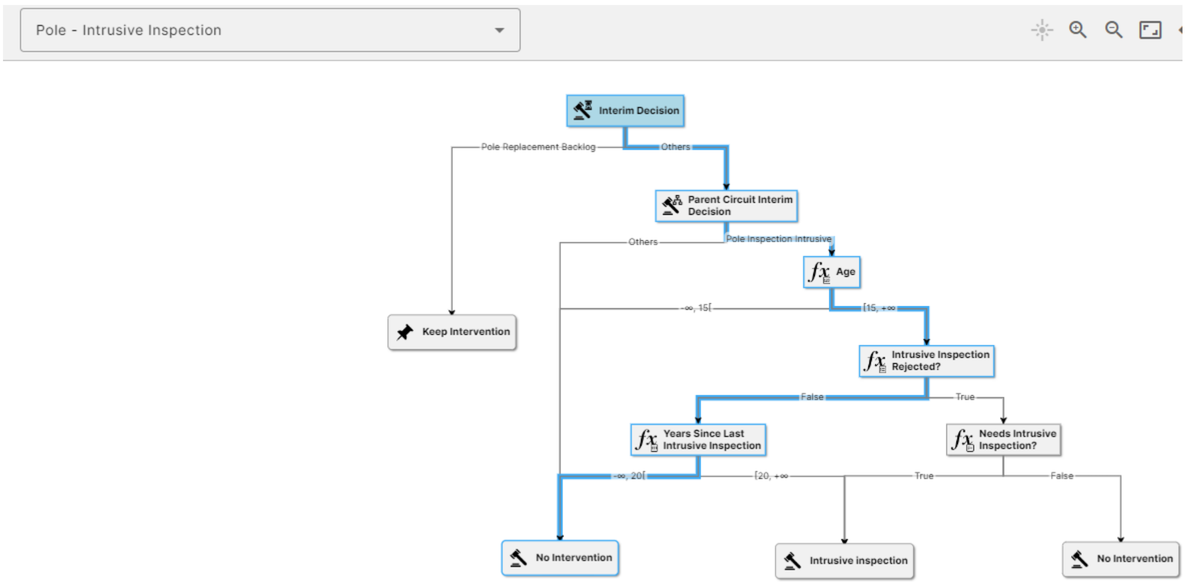
Given that inspection cycle frequencies are set at the circuit level, the decision tree must validate whether the parent circuit of Pole 0593BV, Goldmine Circuit, is triggered for detailed inspection. Between 2023 and 2027, no detailed inspections take place on Goldmine Circuit, as this circuit is set on a 5-year cycle starting in 2028:



Intrusive Inspections

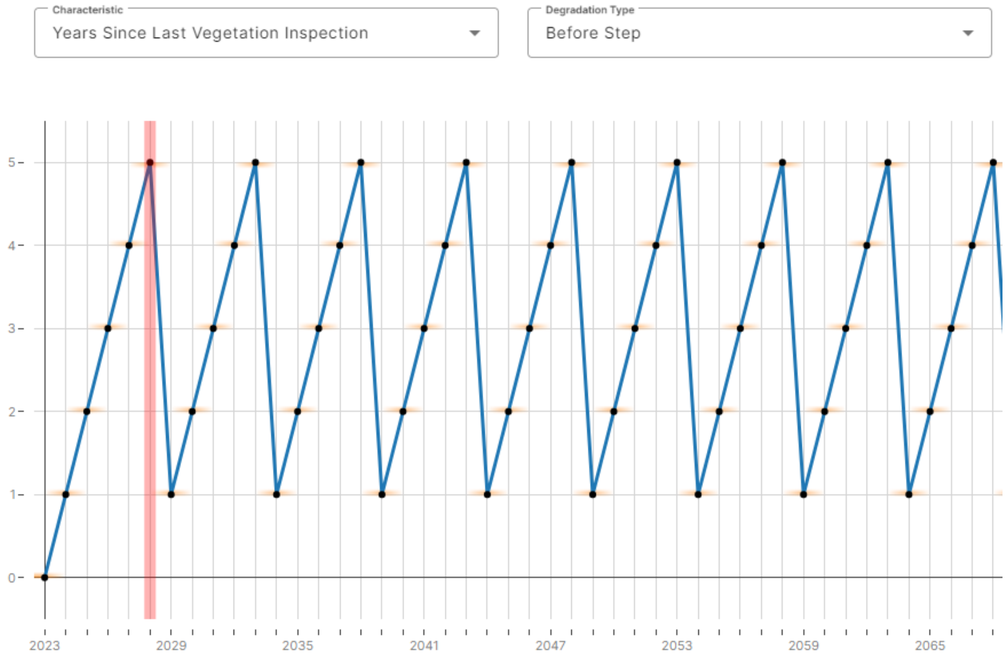
Intrusive inspection cycle frequencies are set at the pole level, but the information is brought to the parent circuit level to optimize the prioritization of interventions. In other words, if a pole is marked for intrusive inspection – is 10 years since its previous intrusive inspection – all other poles within that circuit that meet the criteria for intrusive inspections will be inspected. In 2023, Pole 0593BV is

triggered for intrusive inspection, therefore all other poles within Goldmine Circuit will run through the intrusive inspection decision tree. Because Pole 0593BV is over 15 years old and the model has triggered a “Passed” status on its previous intrusive inspection, the inspection cycle is set to 20 years. The years since the pole’s last intrusive inspection is 12 years, therefore it does not require one in 2023.

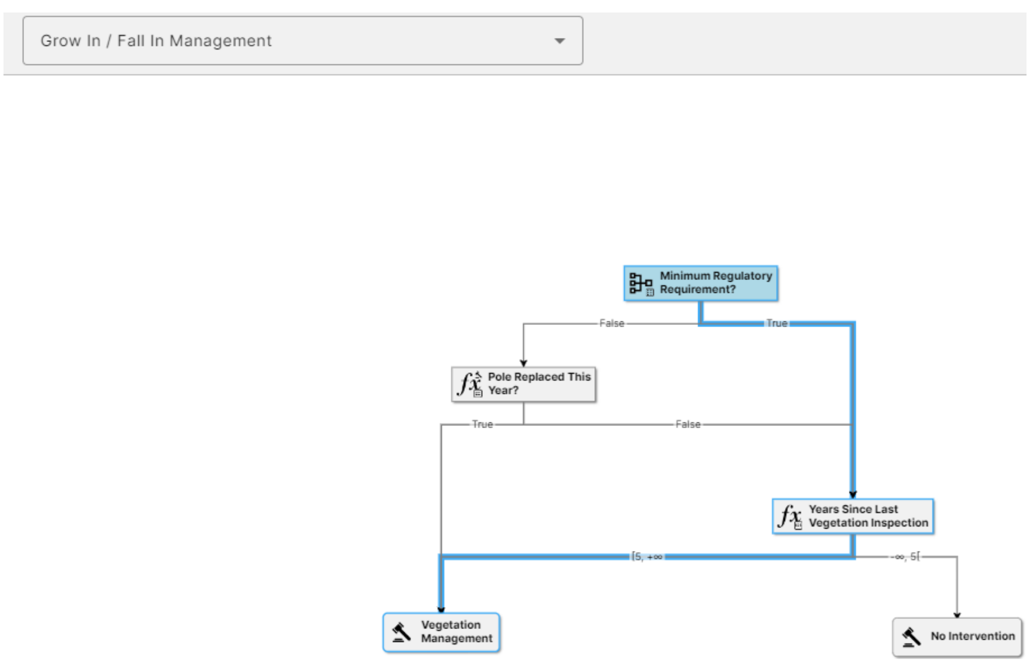


Grid Hardening

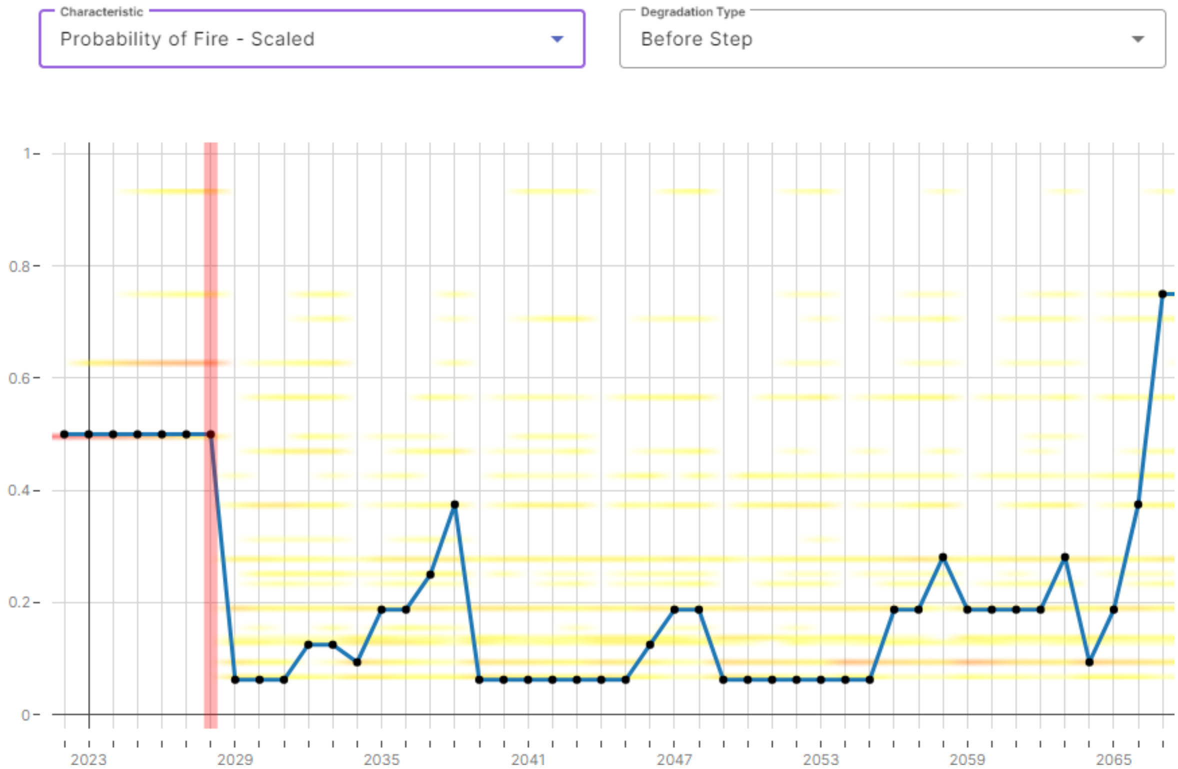
As part of the GO.165 minimum requirements, vegetation management around poles takes place every 5 years. As seen in the image below, vegetation management occurs on Pole 0593BV in 2028.



The decision tree checks whether the years since the last vegetation inspection for each pole is 5 years or over:

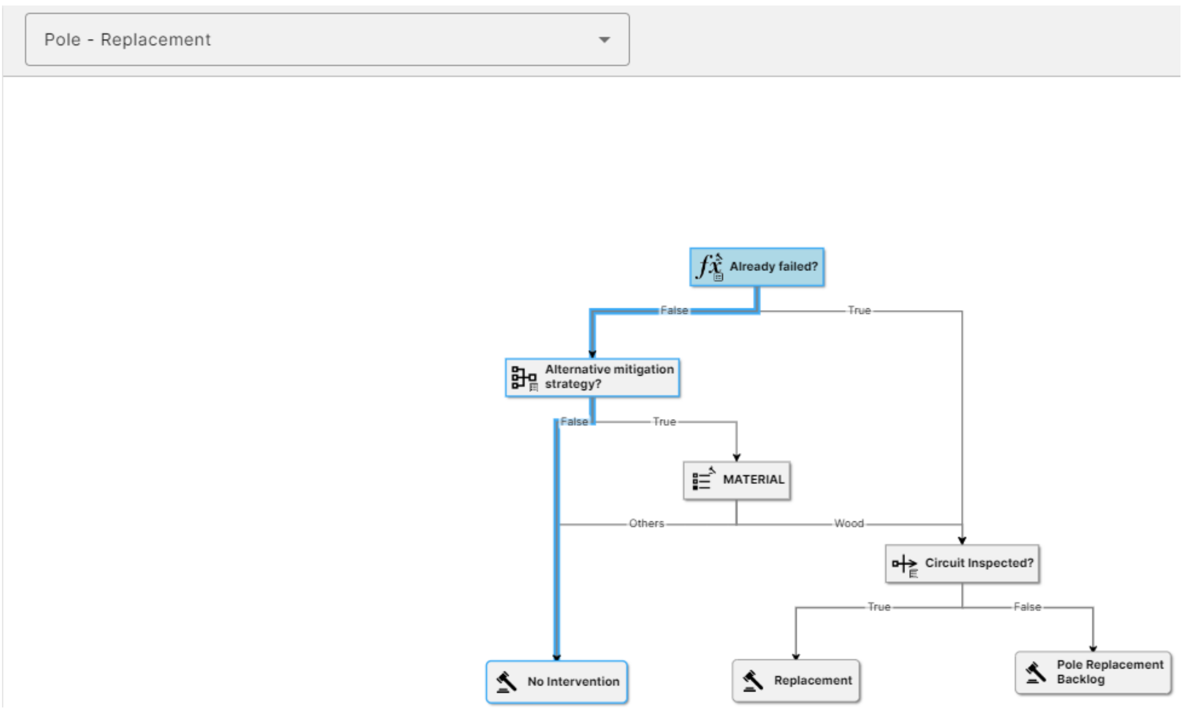


Vegetation management has an impact on risk mitigation, as it reduces the probability of fire for this specific asset which, in turn, reduces its fire risk:

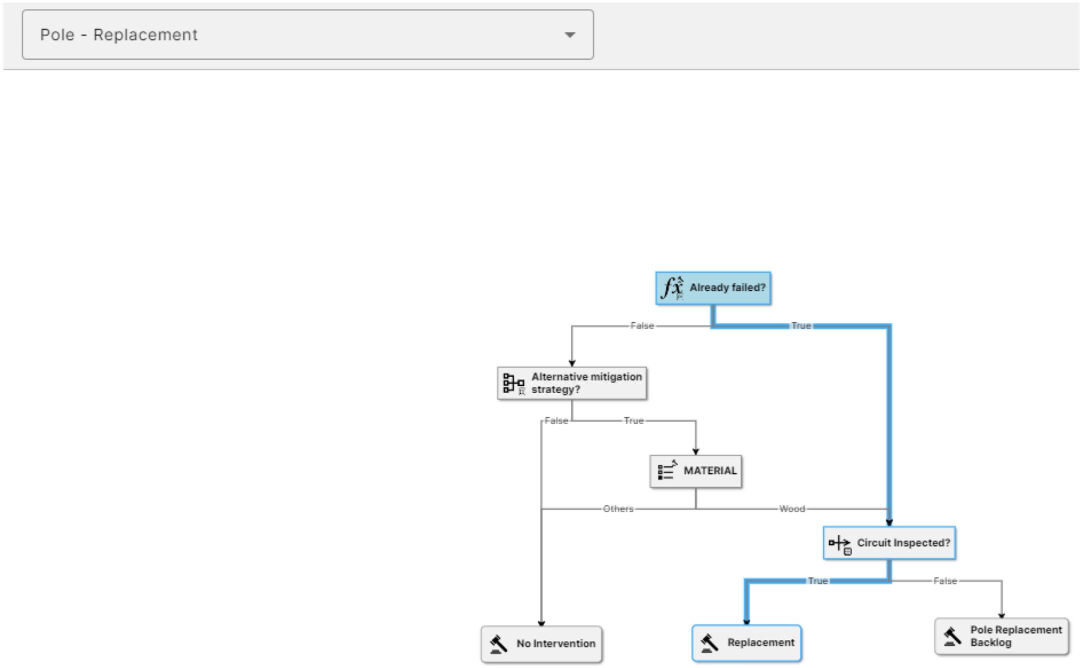


Replacement

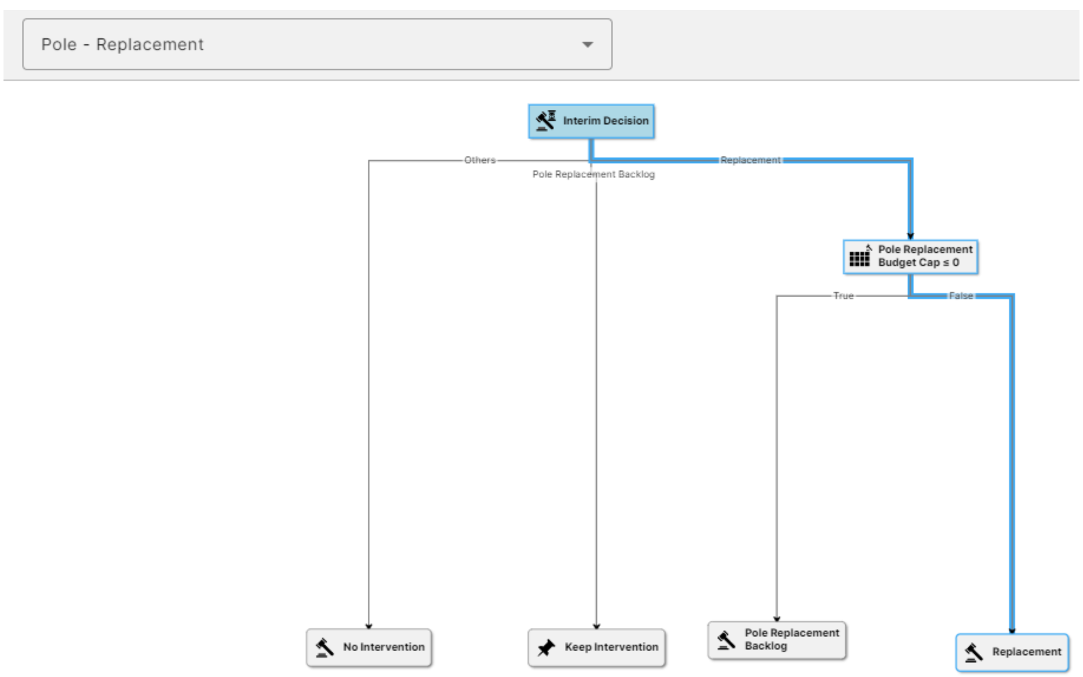
Between 2023 and 2026, the model does not trigger an end-of-life failure on Pole 0593BV and, as a result, is not triggered for replacement:



However, in 2027 the model triggers an end-of-life failure for this pole and because Goldmine Circuit is triggered for intrusive inspection, Pole 0593BV is triggered for replacement.



A pole replacement budget cap is set at $6,000,000 per year. The prioritization order is set at the circuit level, meaning all poles flagged for replacement within an inspected circuit will be replaced, if there is sufficient budget available, before moving to the next circuit in the prioritization order. In this situation, sufficient budget was available to replace poles in Goldmine Circuit.

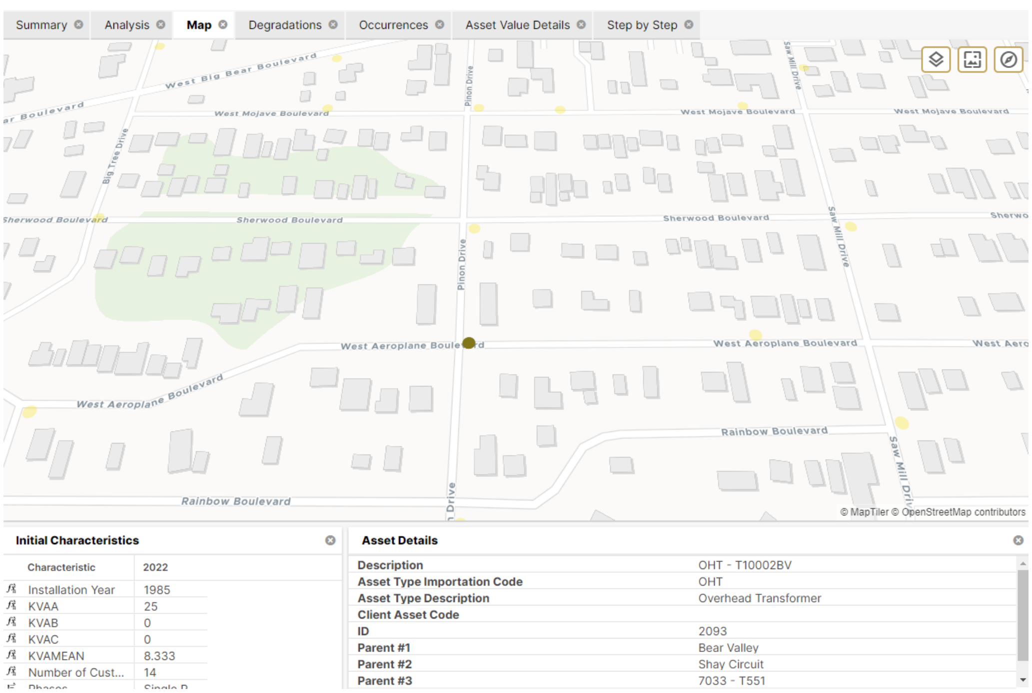


The pole replacement will reset several characteristic values (Age, Years Since Last Detailed Inspection, Years Since Last Intrusive Replacement) as well as trigger replacement costs:

Characteristic	Beginning of Step	End of Step
Age	32	0
Years Since Last Detailed Inspection	4	0
Pole Replacement Backlog - Numerical	1	0
Years Since Last Intrusive Inspection	16	0
Age Range - Map	30-35	0-5
Number of Replacements	0	1
Wood to Steel Ratio - Cost	1	1.204
Wood to Composite Ratio - Cost	1	1.687
Replacement Labor - Cost (Constant	0	10K
Replacement Labor - Cost (Current	0	10K
Total Cost (Constant)	0	15.11K
Replacement - Cost	0	15.11K
Last Detailed Inspection Year	2023	2027
INSTALLDATE	1995	2027
INTINSP_INSPECT_DT	2011	2027
Replacement B Material - Cost	0	2500
Replacement B Material - Cost	0	2500
Replacement Material - Cost (Constant	0	2606
Replacement Material Distribution -	0	2606
Replacement Material - Cost (Current	0	2606

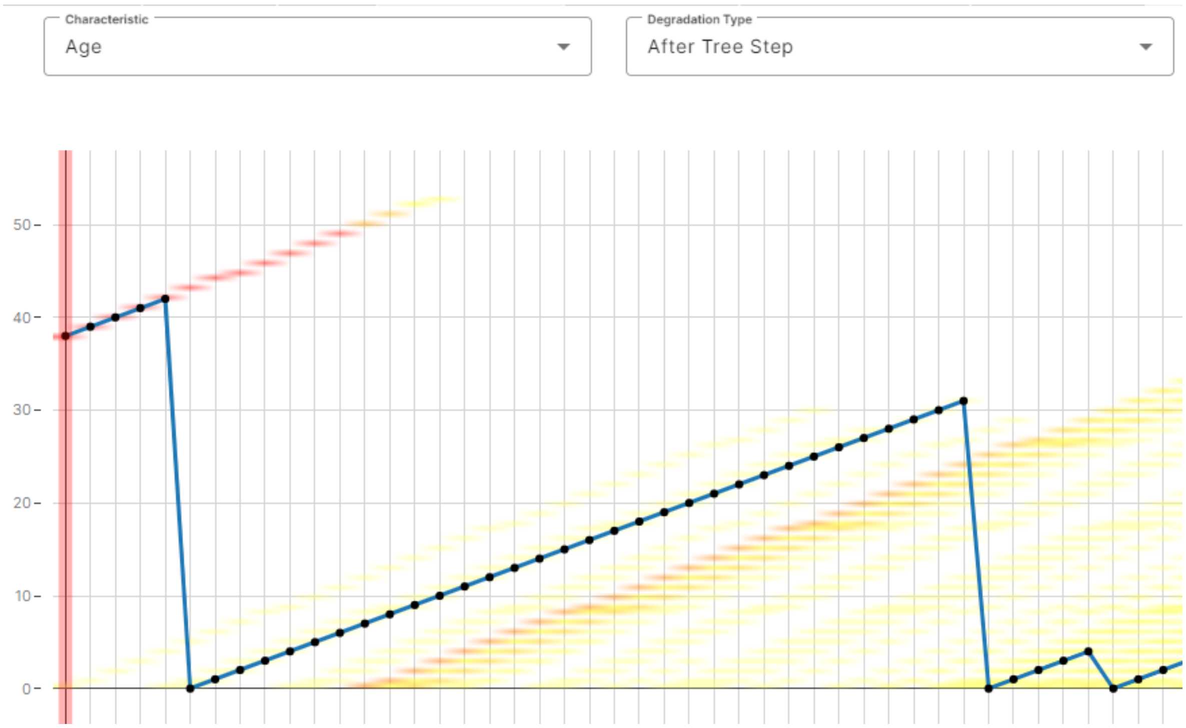
Overhead Transformers

This use case will follow the step-by-step journey of Overhead Transformer T10002BV of iteration 1 between the start of the simulation in 2023, to its replacement in 2028:

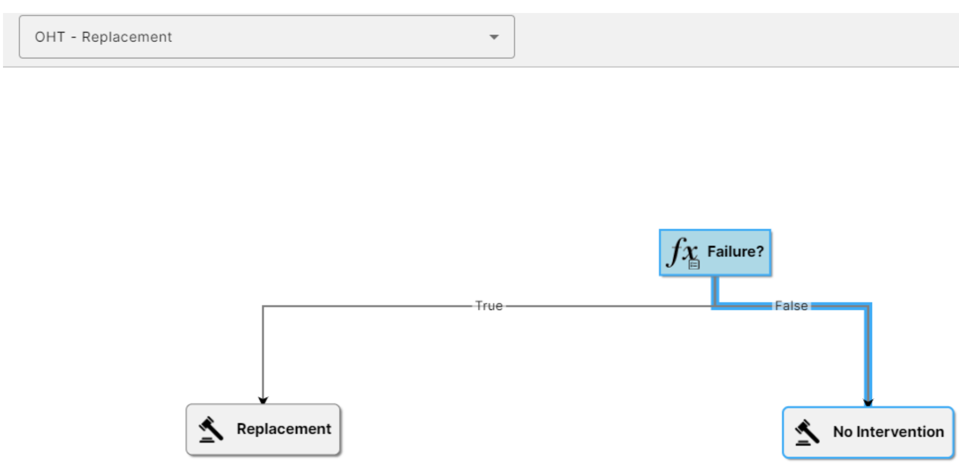


Degradation

The overhead transformer is 38 years of age at the start of the simulation and ages by one year between 2023 and 2027.



Between 2023 and 2027, the model does not trigger a failure for this asset, as seen in the decision tree below:

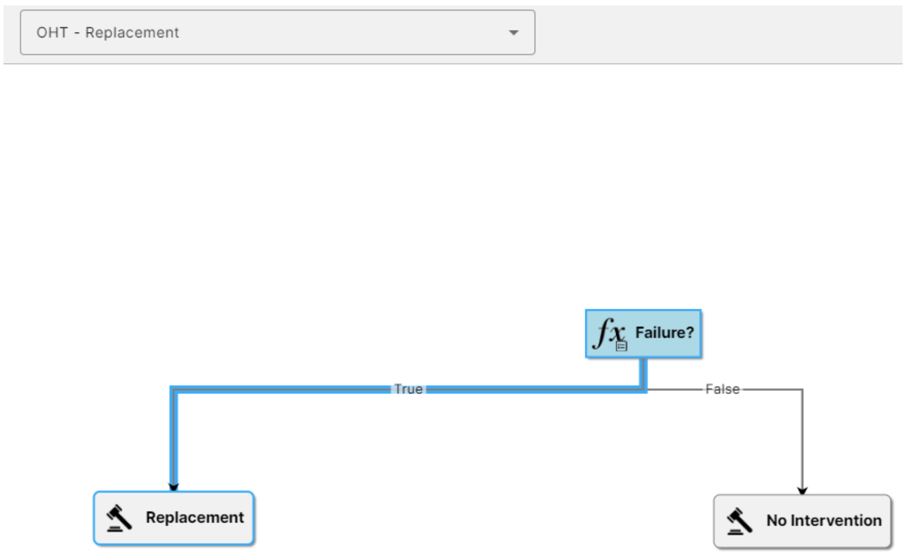


Detailed Inspections – Intrusive Inspections

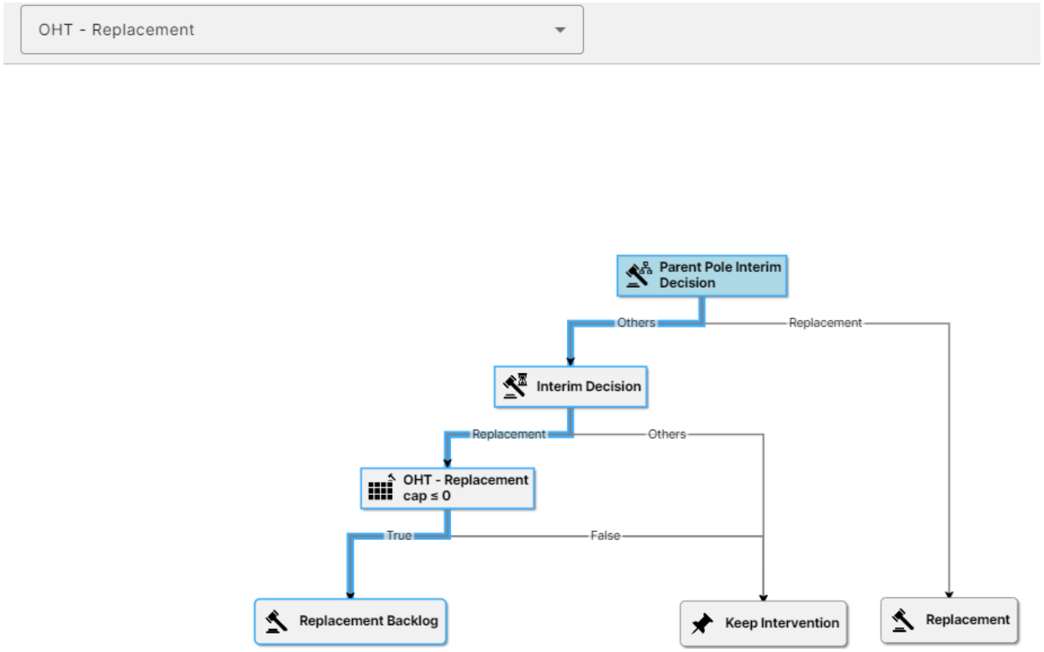
Detailed inspections and intrusive inspections for overhead transformers have not been incorporated in this current phase of the model, as the decision logic has not been defined by BVES.

Replacement

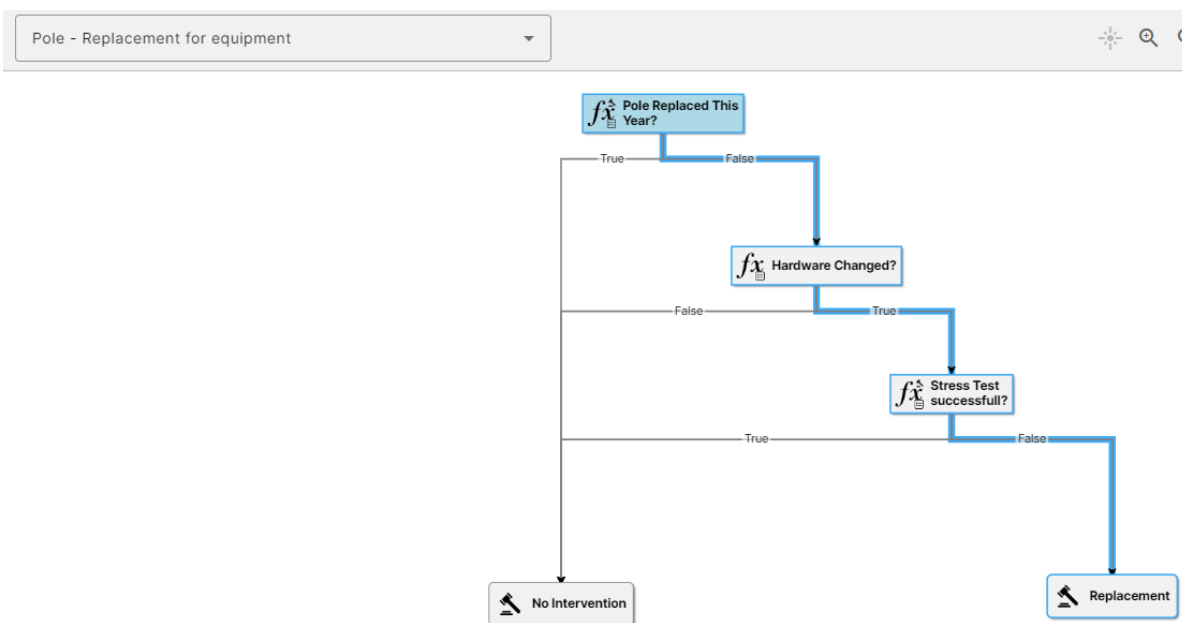
In 2028, the model triggers an end-of-life failure for Overhead Transformer T10002BV:



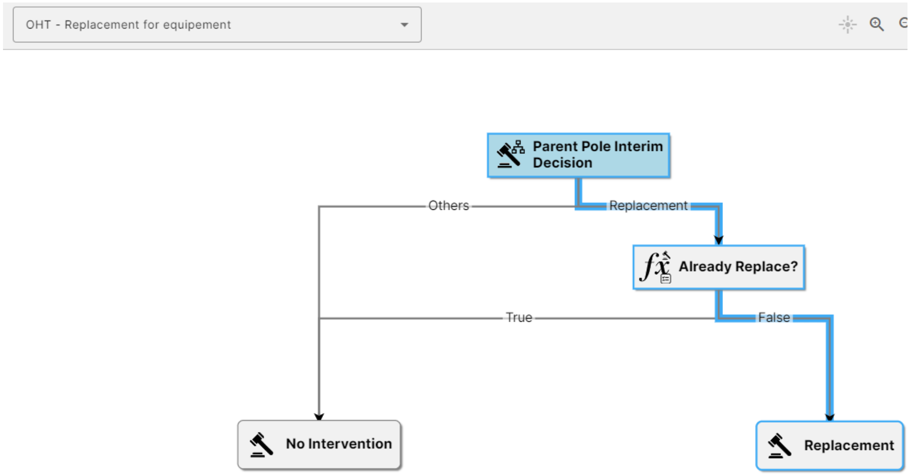
The overhead transformer replacement budget cap is set at $200,000 per year. The prioritization order is set at the circuit level according to fire risk, meaning assets within circuits with the highest average fire risk will be prioritized. before moving to the next circuit in the prioritization order. When the budget reaches below 0, assets of the remaining circuits in the priority list must wait for the following year if they need to be replaced. In this situation, the OHT replacement budget was below 0 when OHT T10002BV ran through the decision tree and was marked as Replacement Backlog.



However, the parent of OHT T10002BV, Pole 10002BV was marked for replacement as the model has triggered a failed stress test:



The decision tree considers the logic that any equipment on a pole needing replacement will also be replaced:

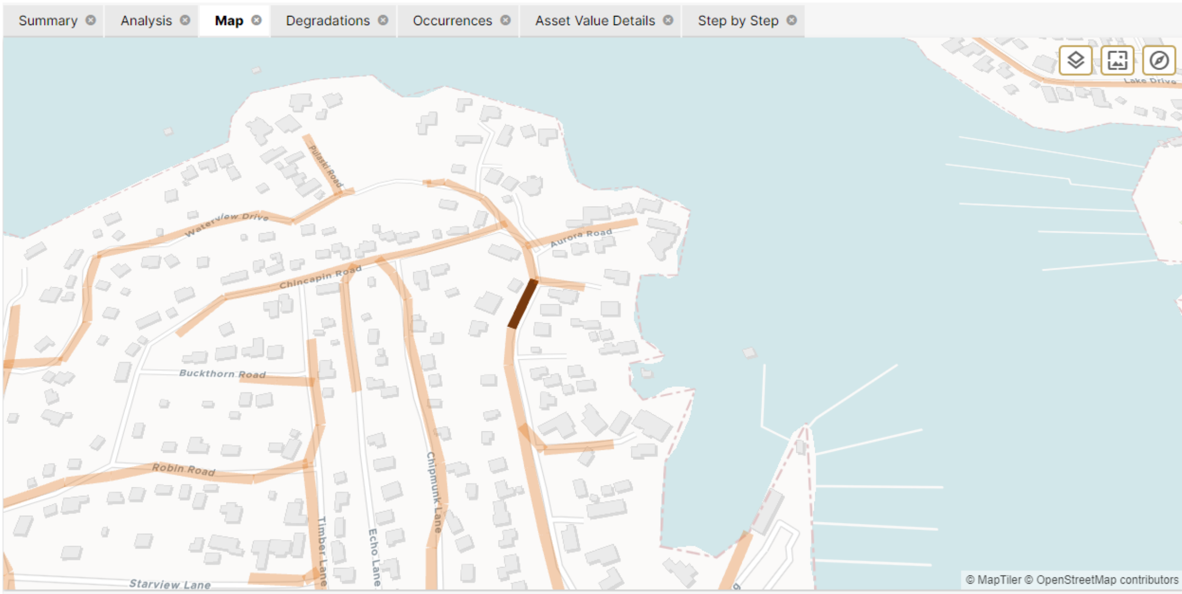


The overhead transformer replacement will reset several characteristic values (Age, Probability of Failure, Probability of Fire, CM – Overhead Transformer Failure) as well as trigger replacement costs:

Characteristic	Beginning of Step	End of Step
Age	43	0
Age Range - Map	40-45	0-5
Already Failed?	True	False
Already Replace?	False	True
B material - Cost (Constant Value)	0	1200
B material - Cost (Current Value)	0	1200
CM - Overhead Transformer Failure	1.005	1.002
Failure - Numerical	1	0
Failure?	True	False
Installation Year	1985	2028
Labor Cost (Constant Value)	0	1075
Labor Cost (Current Value)	0	1075
Number of Replacements	0	1
Probability of Failure	0.006639	0.003
Probability of Failure - Choice	4	3
Probability of failure - Score	4	3
Probability of fire - Final	0.5023	0.501
Replacement Cost Total	0	5191
Replacement Material - Cost (Constant	0	2916
Replacement Material - Cost (Current	0	2916

Overhead Conductor

This use case will follow the step-by-step journey of Overhead Conductor OH_10008 T10002BV of iteration 1 between the start of the simulation in 2023, to its replacement in 2037:



Initial Characteristics

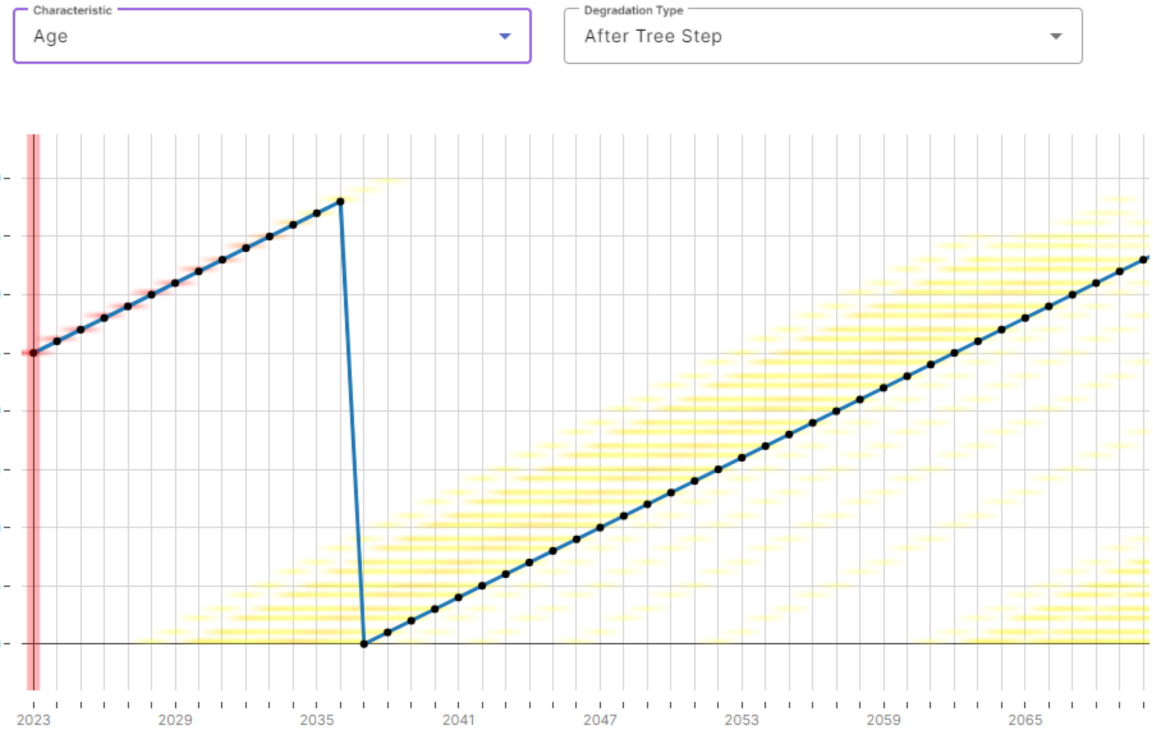
Characteristic	2022
Conductor Length	207.2
Conductor Material	Copper ...
CONDUCTORTYPE	Bare
INSTALLDATE	1998
StandardConductorOD	0.162
wmBaseKv	4.16

Asset Details

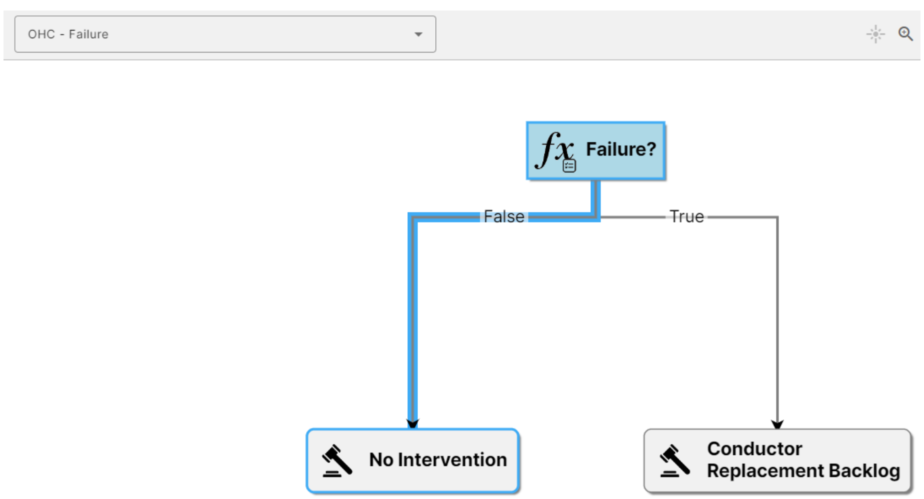
Description	OH_10008
Asset Type Importation Code	OHC
Asset Type Description	Overhead Conductor
Client Asset Code	OH_10008
ID	3045
Parent #1	Bear Valley
Parent #2	Boulder Circuit
Parent #3	2230 - D2229

Degradation

The overhead transformer is 25 years of age at the start of the simulation and ages by one year between 2023 and 2037.



Between 2023 and 2036, the model does not trigger a failure for this asset, as seen in the decision tree below:

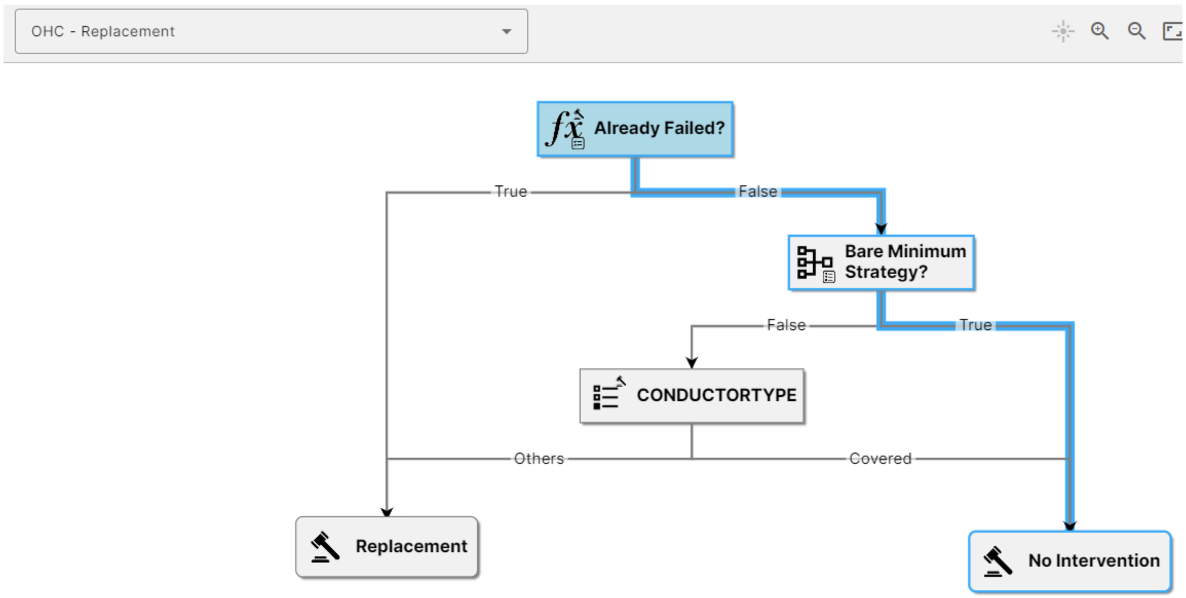


Detailed Inspections – Intrusive Inspections

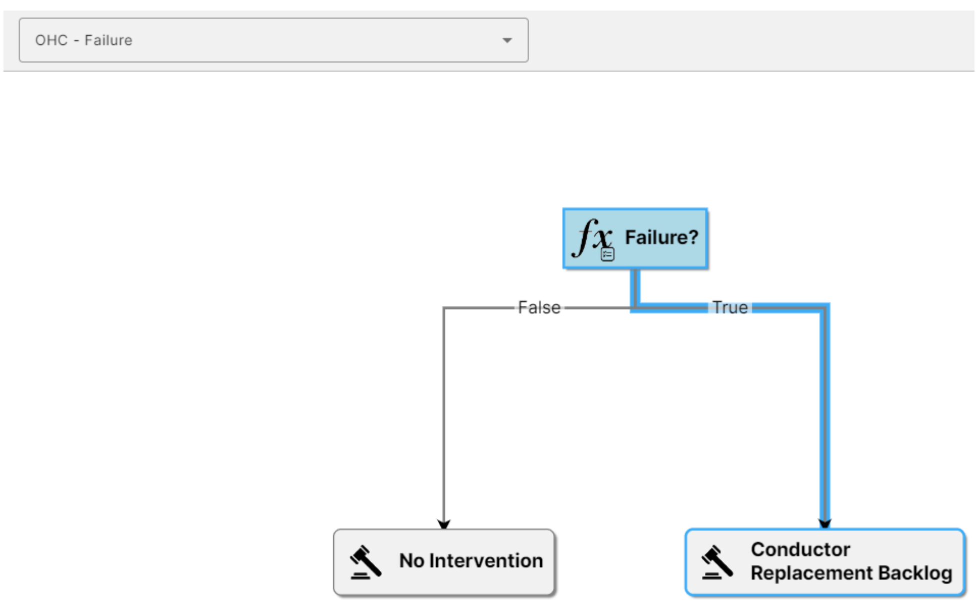
Detailed inspections and intrusive inspections for overhead conductors have not been incorporated in this current phase of the model, as the decision logic has not been defined by BVES.

Replacement

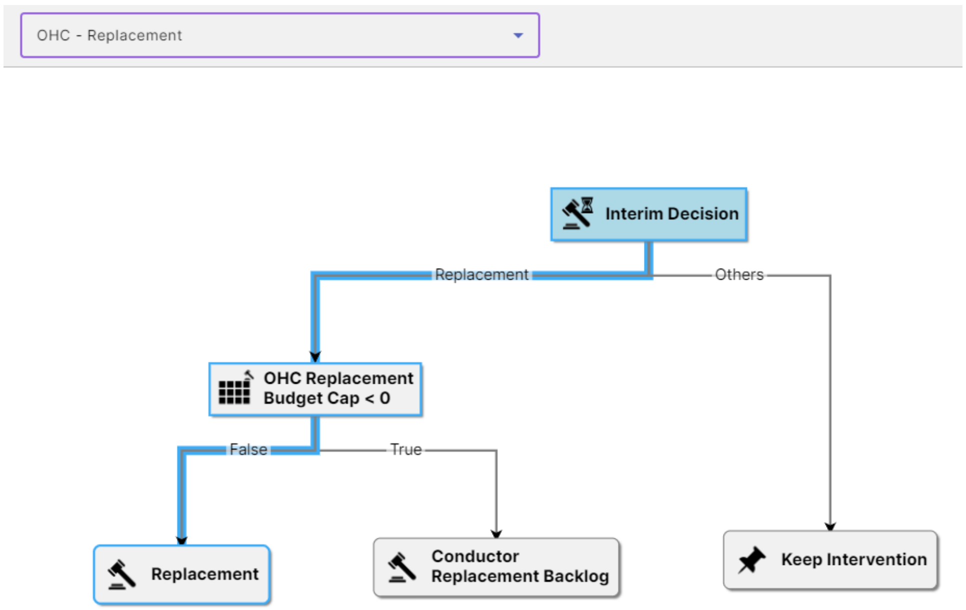
From 2023 to 2036, no interventions are performed on OH_10008; no end-of-life failures are triggered and the GO.165 minimum requirements use case does not include any proactive replacements to mitigate fire risk:



In 2037, the model triggers an end-of-life failure on OH_10008:



The overhead conductor replacement budget cap is set at $2,000,000 per year. The prioritization order is set at the circuit level according to fire risk, meaning assets within circuits with the highest average fire risk will be prioritized. before moving to the next circuit in the prioritization order. When the budget reaches below 0, assets of the remaining circuits in the priority list must wait for the following year if they need to be replaced. In this situation, the overhead conductor replacement budget was above 0 when OH_10008 ran through the decision tree and was marked as Replacement.



The overhead conductor replacement will reset several characteristic values (Age, Probability of Failure, Installation year) as well as trigger replacement costs:

Characteristic	Beginning of Step	End of Step
Age	39	0
Age Range - Map	35-40	0-5
Already Failed?	True	False
Conductor Changed?	False	True
Conductor Replacement Backlog - Numerical	1	0
Conductor Replacement Backlog?	True	False
INSTALLDATE	1998	2037
Number of Overhead Conductor Replacement	0	1
Replacement Cost Total	0	3977
Replacement Labor - Cost (Constant Value)	0	3500
Replacement Labor - Cost (Current Value)	0	3500
Replacement Material - Cost (Constant Value)	0	476.6
Replacement Material - Cost (Current Value)	0	476.6
Total Cost (Constant)	0	3977

Under the minimum requirements for GO.165, the bare to covered conductor replacement program is not considered. As a result, there are no risk mitigation strategies evaluated for overhead conductors under this use case.

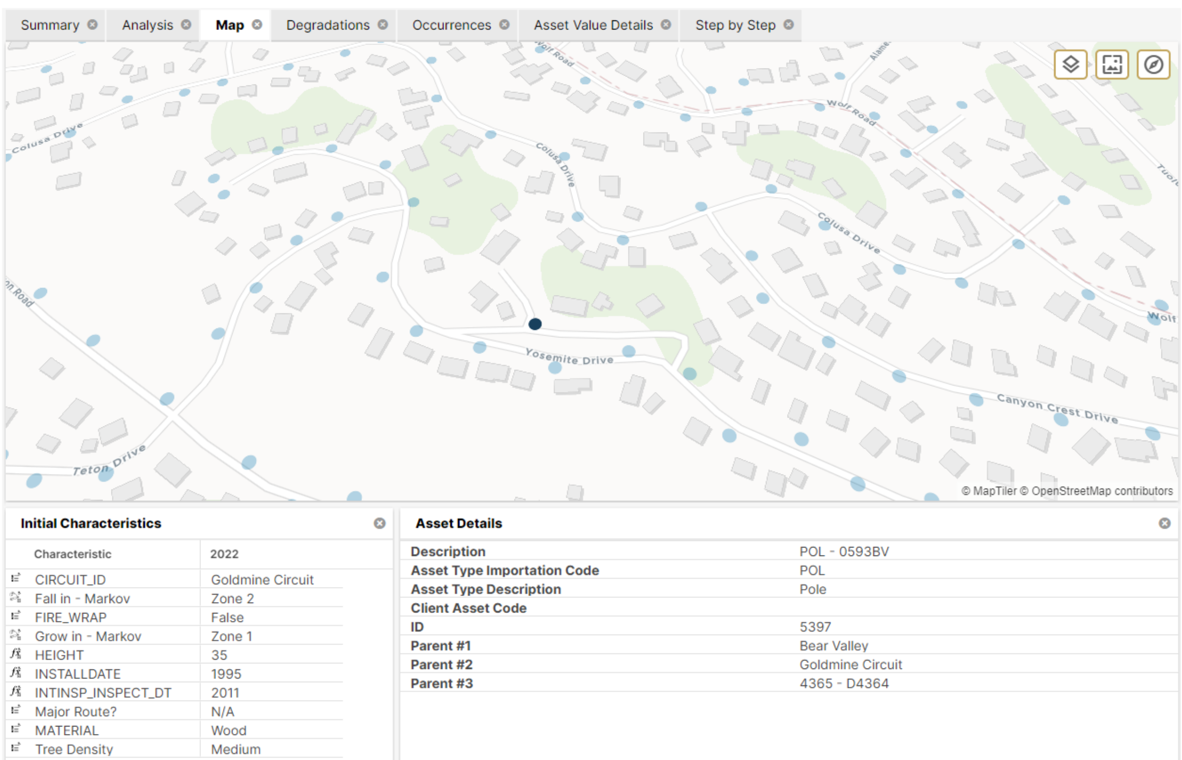
Current BVES Strategy

In addition to the minimum requirements under GO.165, this use case evaluates the impact of the following risk mitigation strategies:

1. Installation of fire wraps on poles
2. Proactive replacement of bare conductors
3. Implementation of vegetation management strategies

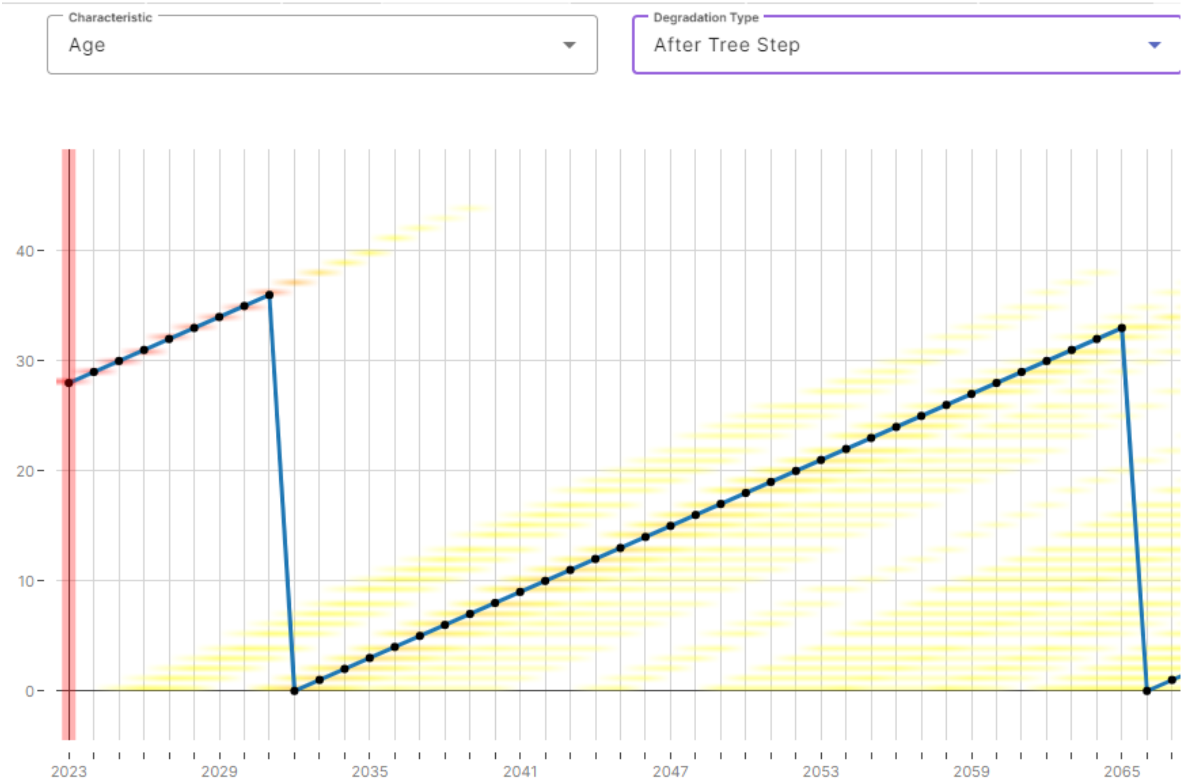
Poles

This use case will follow the step-by-step journey of Pole 0593BV of iteration 1 between the start of the simulation in 2023, to its replacement in 2031:

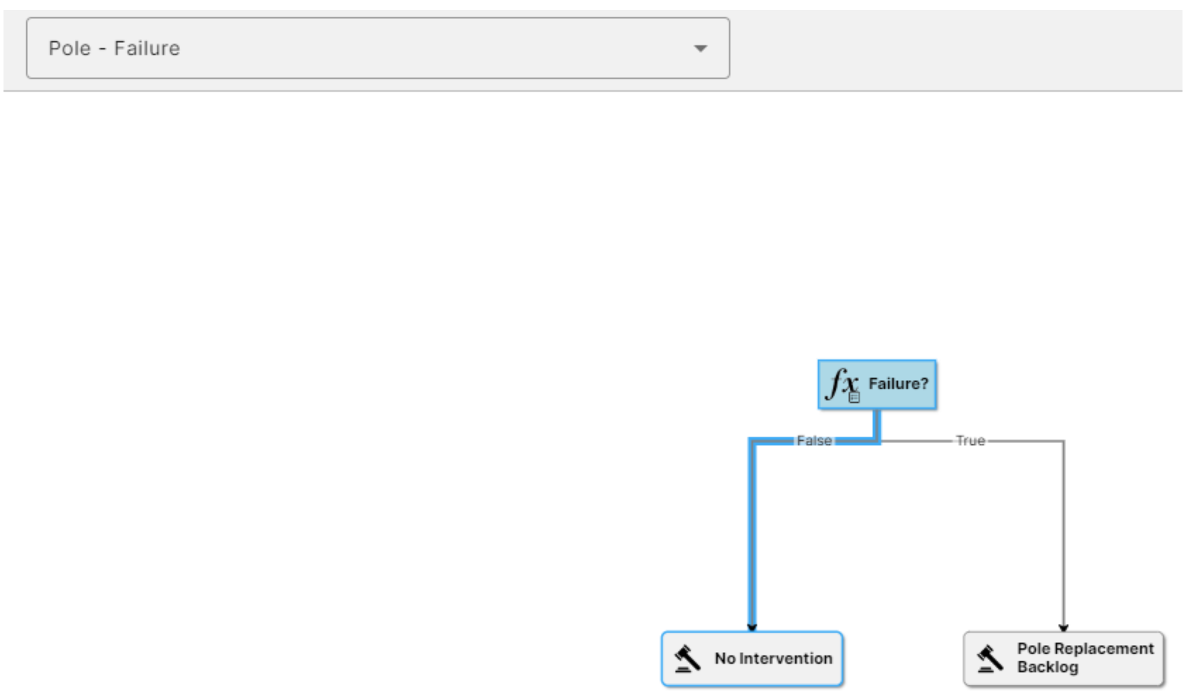


Degradation

The pole is 28 years of age at the start of the simulation and ages by one year between 2023 and 2032.

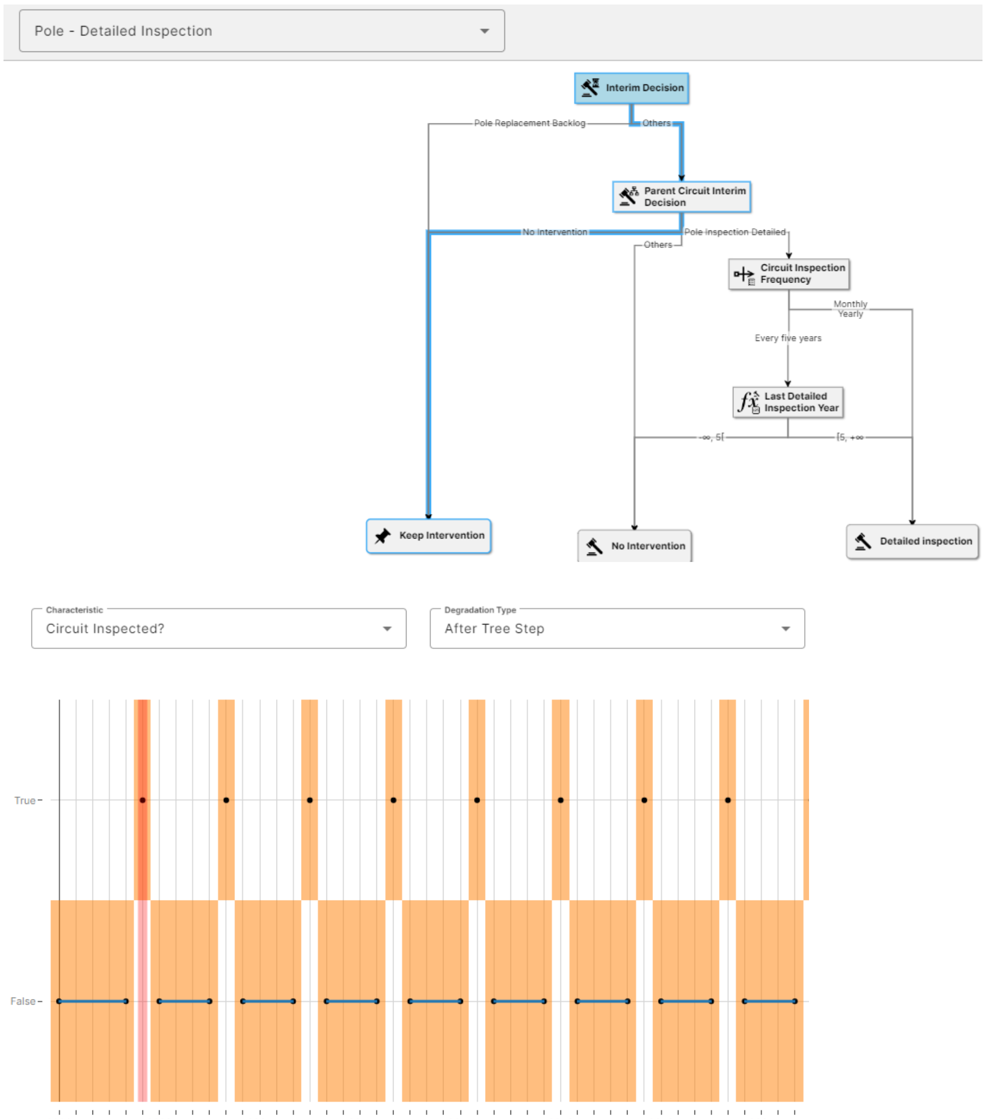


Between 2023 and 2031, the model does not trigger a failure for this asset, as seen in the decision tree below:



Detailed Inspections

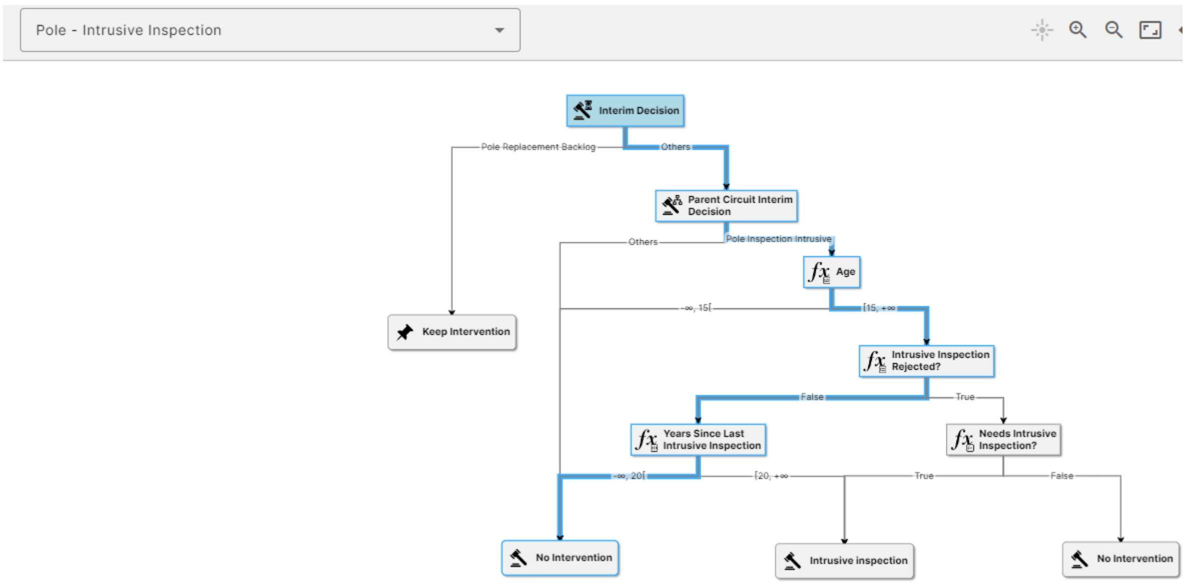
Given that inspection cycle frequencies are set at the circuit level, the decision tree must validate whether the parent circuit of Pole 0593BV, Goldmine Circuit, is triggered for detailed inspection. Between 2023 and 2027, no detailed inspections take place on Goldmine Circuit, as this circuit is set on a 5-year cycle starting in 2028:



Intrusive Inspections

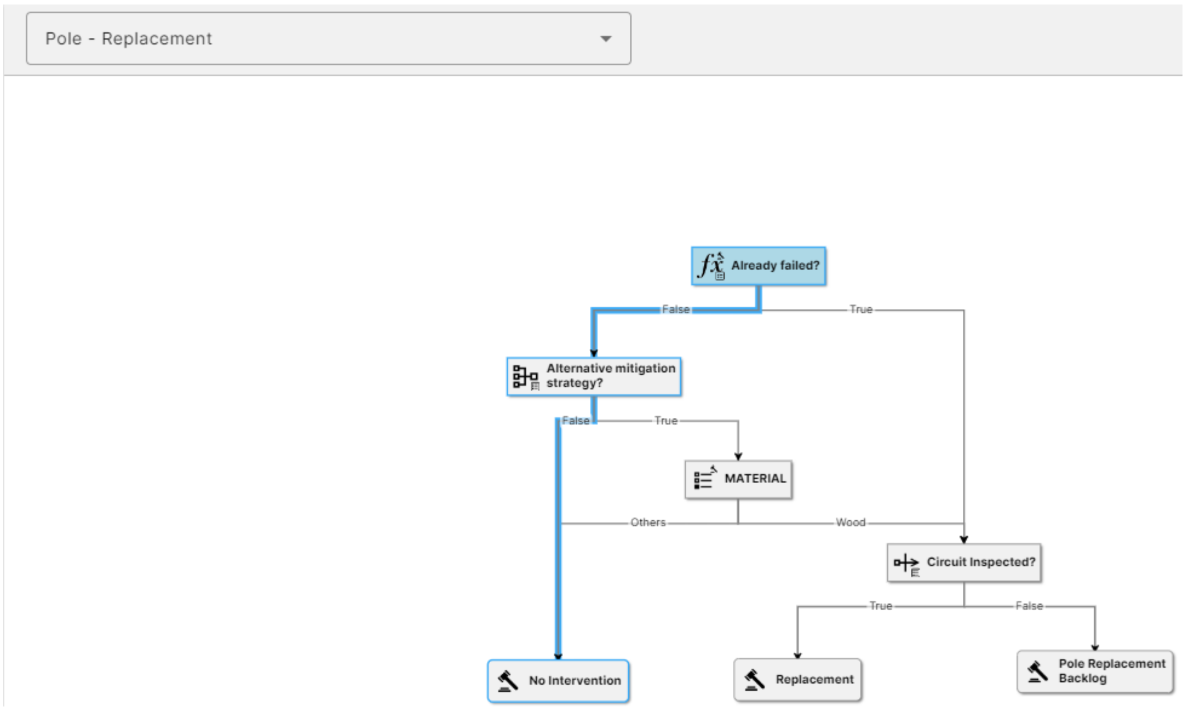
Intrusive inspection cycle frequencies are set at the pole level, but the information is brought to the parent circuit level to optimize the prioritization of interventions. In other words, if a pole is marked for intrusive inspection – is 10 years since its previous intrusive inspection – all other poles within that circuit that meet the criteria for intrusive inspections will be inspected. In 2023, Pole 0593BV is

triggered for intrusive inspection, therefore all other poles within Goldmine Circuit will run through the intrusive inspection decision tree. Because Pole 0593BV is over 15 years old and the model has triggered a “Passed” status on its previous intrusive inspection, the inspection cycle is set to 20 years. The years since the pole’s last intrusive inspection is 12 years, therefore it does not require one in 2023.

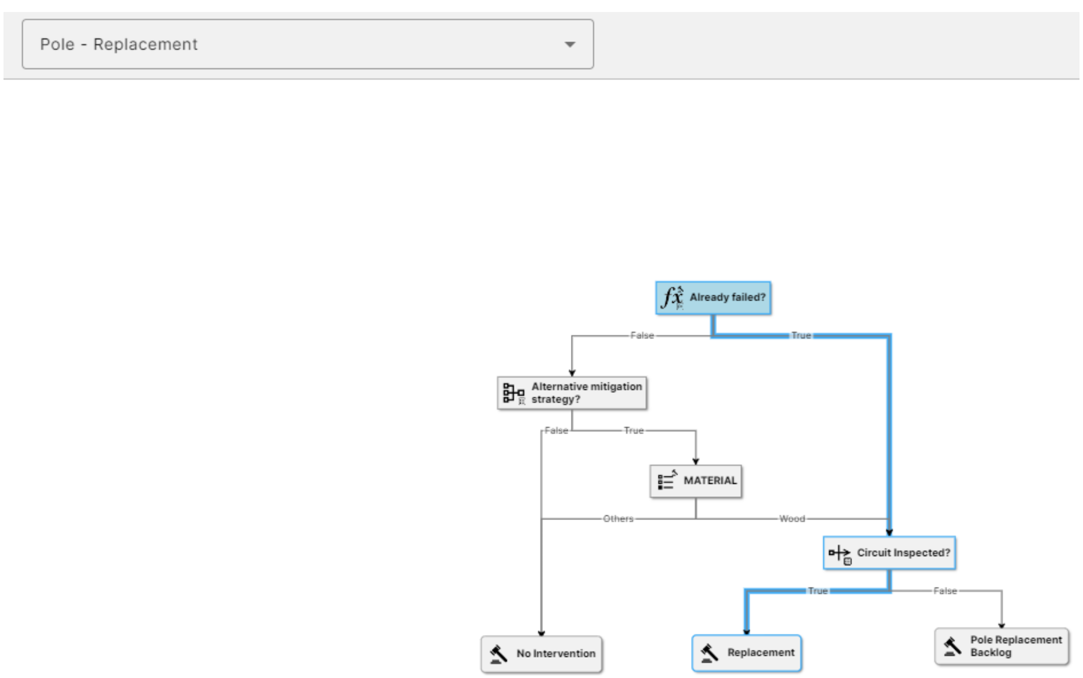


Replacement

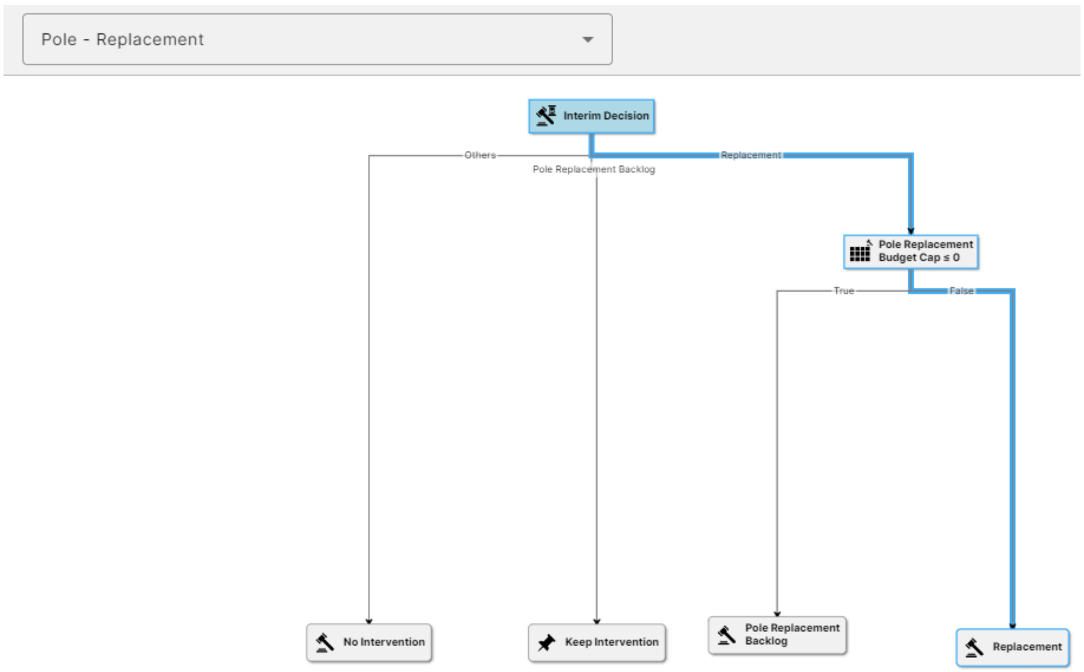
Between 2023 and 2031, the model does not trigger an end-of-life failure on Pole 0593BV and, as a result, is not triggered for replacement:



However, in 2032 the model triggers an end-of-life failure for this pole and because Goldmine Circuit is triggered for intrusive inspection, Pole 0593BV is triggered for replacement.



A pole replacement budget cap is set at $6,000,000 per year. The prioritization order is set at the circuit level, meaning all poles flagged for replacement within an inspected circuit will be replaced, if there is sufficient budget available, before moving to the next circuit in the prioritization order. In this situation, sufficient budget was available to replace poles in Goldmine Circuit.

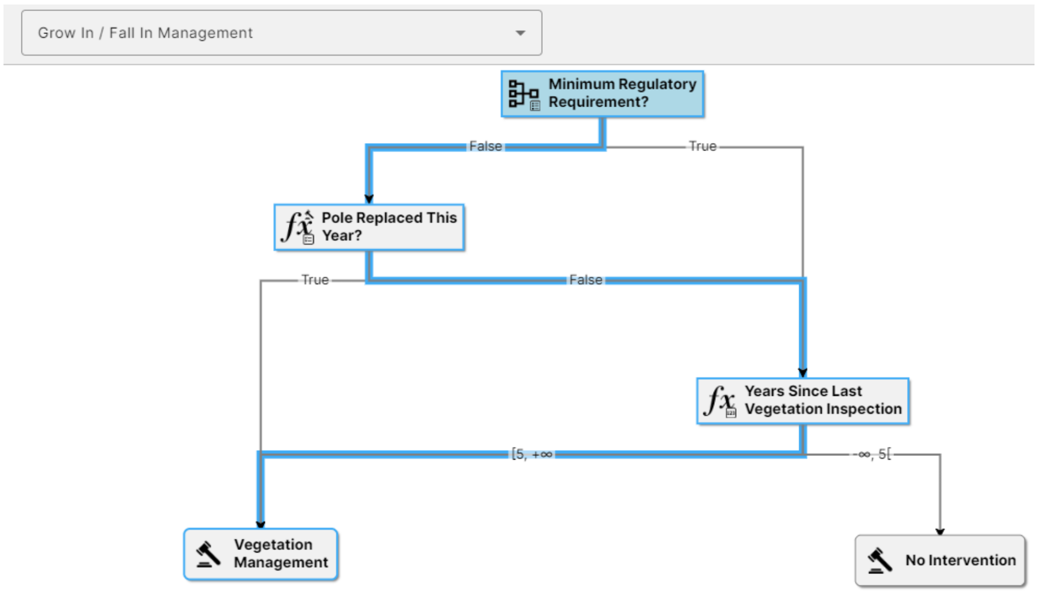


The pole replacement will reset several characteristic values (Age, Years Since Last Detailed Inspection, Years Since Last Intrusive Replacement) as well as trigger replacement costs:

Characteristic	Beginning of Step	End of Step
Age	37	0
Age Range - Map	35-40	0-5
Already failed?	True	False
Asset is replaced?	False	True
Inspection Age Choice	Age-1	Age-0
INSTALLDATE	1995	2032
INTINSP_INSPECT_DT	2031	2032
Last Detailed Inspection Year	2028	2032
Number of Replacements	0	1
Pole Replaced This Year?	False	True
Pole Replacement Backlog - Numerical	1	0
Pole Replacement Backlog?	True	False
Replacement - Cost	0	15.37K
Replacement B Material - Cost	0	2500
Replacement B Material - Cost	0	2500
Replacement Labor - Cost (Constant	0	10K
Replacement Labor - Cost (Current	0	10K
Replacement Material - Cost (Constant	0	2872
Replacement Material - Cost (Current	0	2872

Grid Hardening

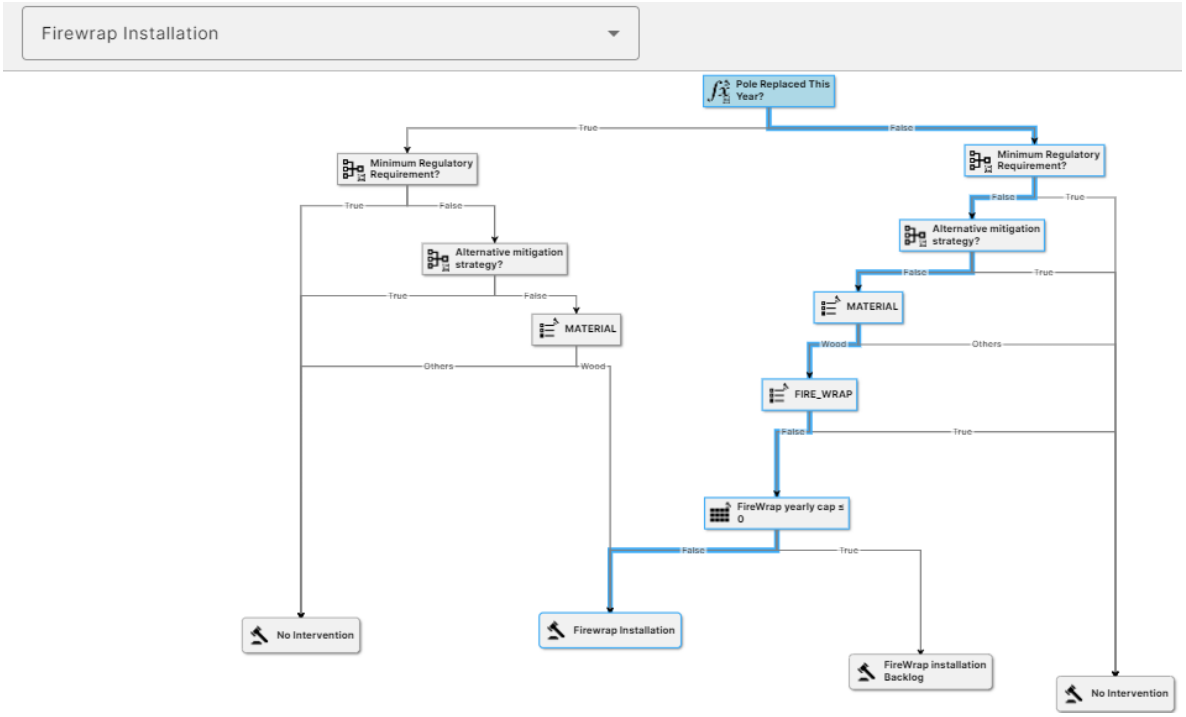
There are two interventions included in the grid hardening step: vegetation management and fire wrap installation. Vegetation management occurs around poles every five years as well as for all newly installed poles. The first vegetation management intervention on Pole 0593BV takes place in 2028, as it marks 5 years since the previous vegetation management intervention.



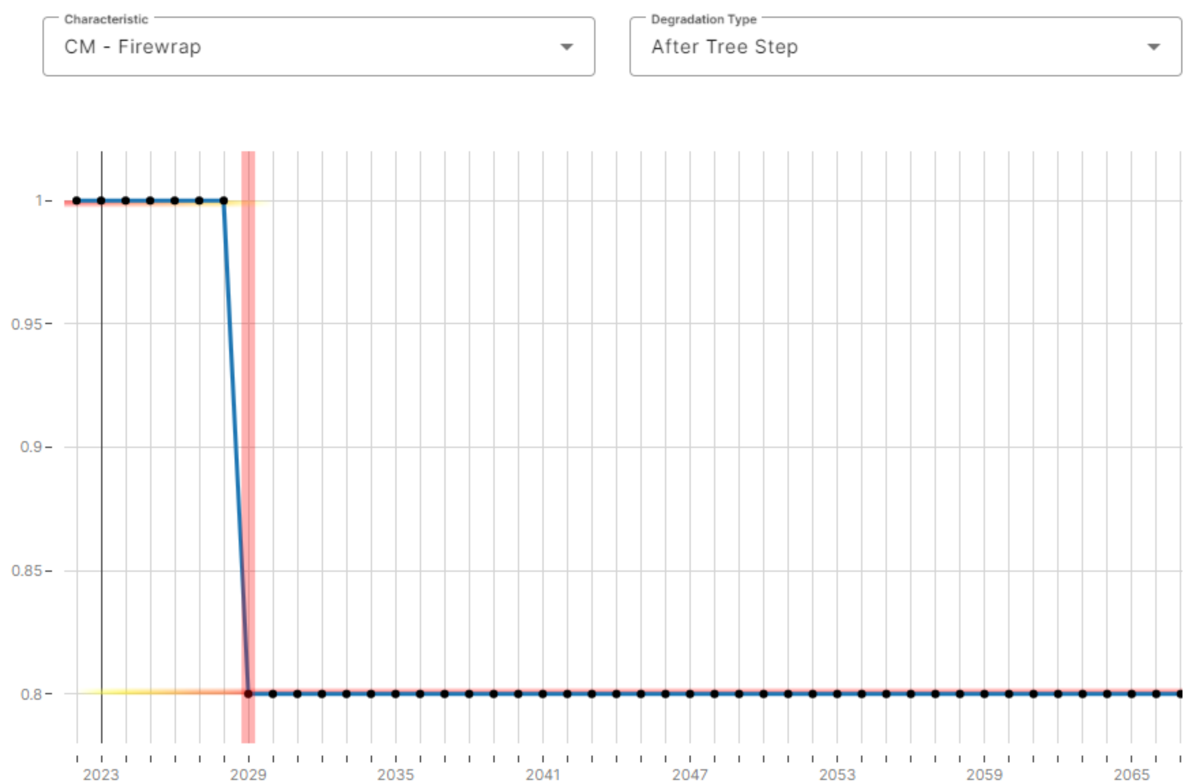
As a result, indicators such as the “CM – Vegetation” coefficient, fire risk, and the probability of fire are reduced for this asset:

Characteristic	Beginning of Step	End of Step
CM - Final	1	0.375
CM - Vegetation	1	0.375
CM - Vegetation Management (Fall In)	1	0.75
CM - Vegetation Management (Grow	1	0.5
Fall in - Markov	Zone 2	Zone 3
Fire Risk (Test)	27	6.75
Grow in - Markov	Zone 1	Zone 3
Last Vegetation Inspection Year	2023	2028
LiDAR Inspection - Cost (Constant	0	18
LiDAR Inspection - Cost (Current	0	18
Probability of Fire - Final - Range	4	1
Probability of Fire - Scaled	0.5	0.1875

Under the current BVES strategy, fire wrapping is installed on a maximum of 500 wooden poles per year. Wood poles located along a major route are prioritized first for fire wrapping. Wood poles triggered for fire wrapping but placed in the backlog due to the yearly cap of 500 being reached, represent the second order of prioritization. Between 2023 and 2028, Pole 0593BV is placed in the fire wrapping installation backlog. In 2029, fire wrapping is installed on the pole:

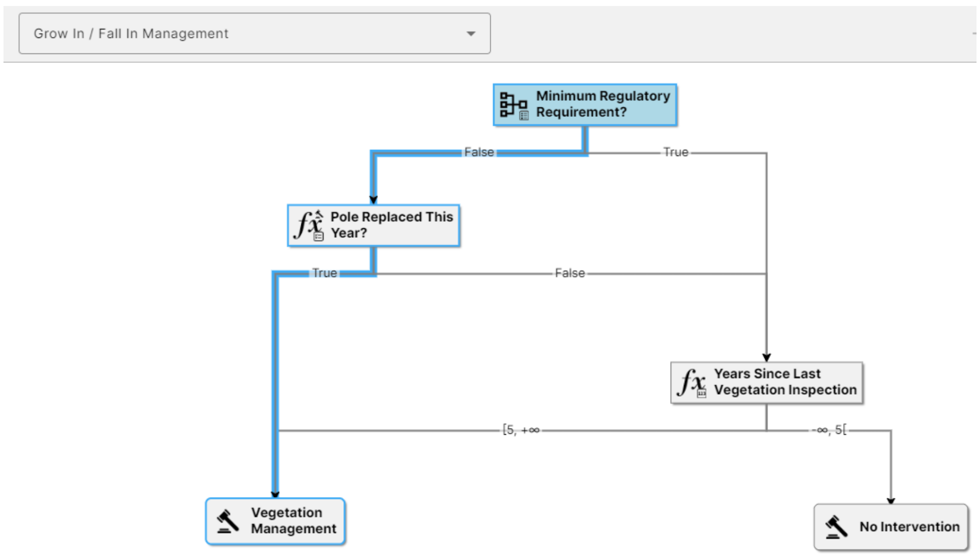


This intervention triggers a reduction in the “CM – Firewrap” coefficient characteristic which, in turn, lowers the probability of fire for this pole:



Characteristic	Beginning of Step	End of Step
CM - Final	0.5	0.4
CM - Firewrap	1	0.8
FIRE_WRAP	False	True
Firewrap - Cost (Constant Value)	0	100
Firewrap - Cost (Current Value)	0	100
Firewrap Backlog - Numerical	1	0
Firewrap Backlog?	True	False
Probability of Fire - Scaled	0.25	0.2
Total Cost (Constant)	9.92	109.9
Yearly Number of Firewrap	0	1

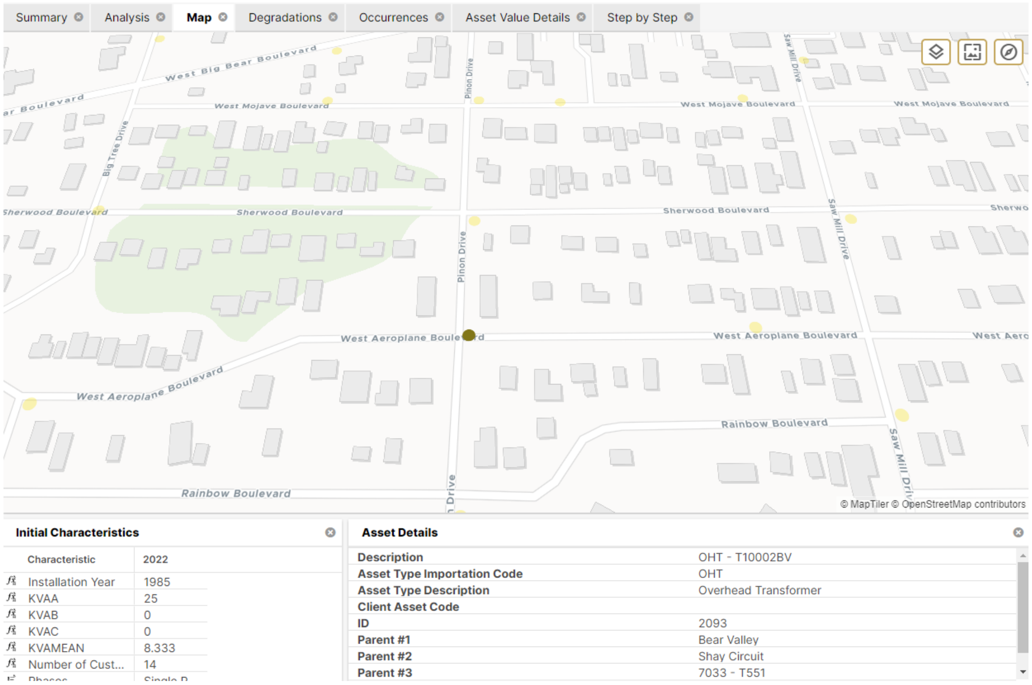
As mentioned earlier, Pole 0593BV is eventually replaced due to an end-of-life failure in 2032. This triggers another vegetation management intervention and further reduces its fire risk:



The short timeframe between the initial fire wrap installation in 2028 and the eventual end-of-life replacement of Pole 0593BV in 2023 suggests there may be opportunities to synchronize these interventions by proactively replacing wood poles that have a high probability of failure. Further analysis would be necessary to determine the appropriate threshold to trigger proactive wood pole replacements and may be discussed as part of future model enhancements.

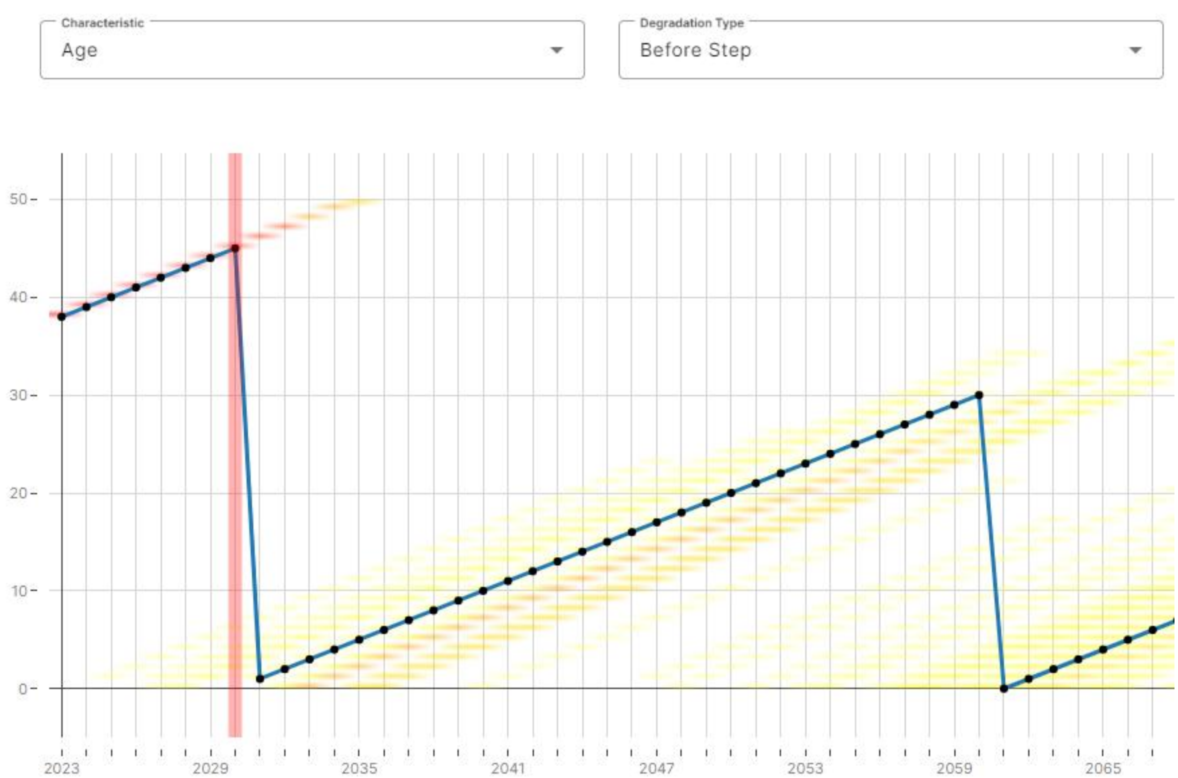
Overhead Transformers

This use case will follow the step-by-step journey of Overhead Transformer T10002BV of iteration 1 between the start of the simulation in 2023, to its replacement in 2030:

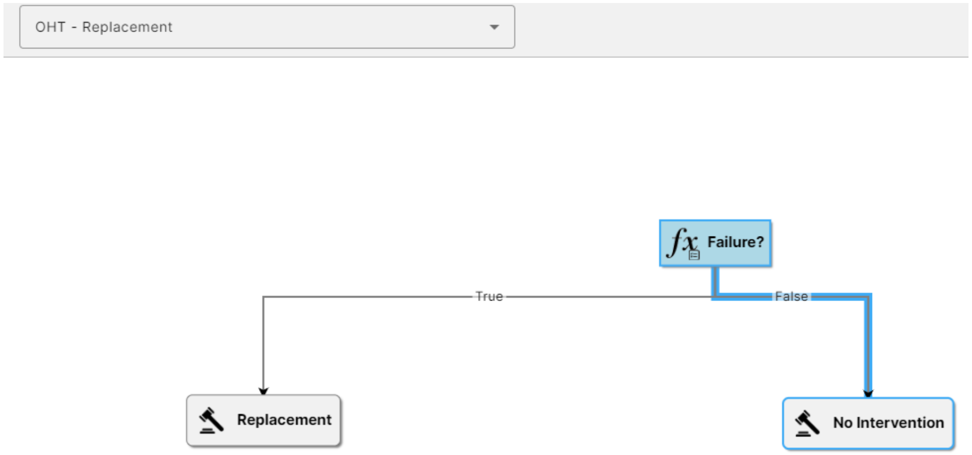


Degradation

The overhead transformer is 38 years of age at the start of the simulation and ages by one year between 2023 and 2030.



Between 2023 and 2029, the model does not trigger a failure for this asset, as seen in the decision tree below:

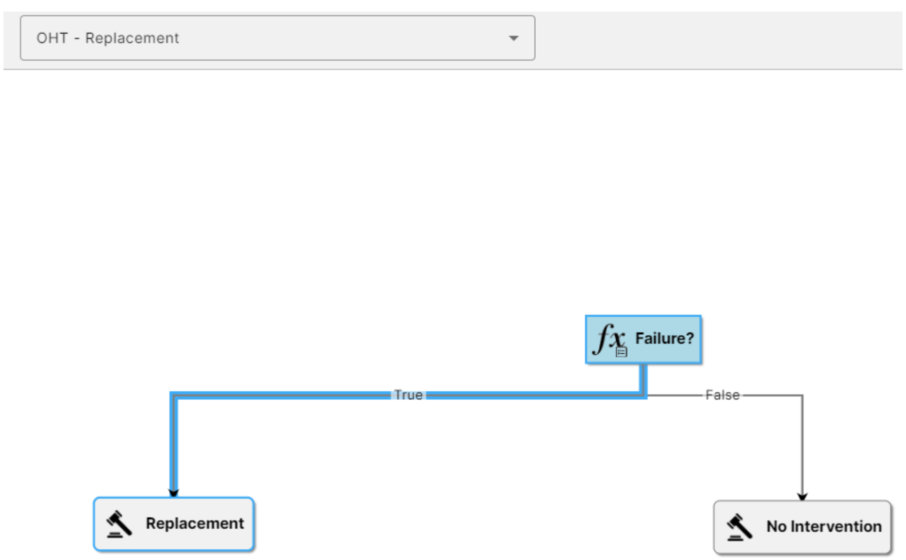


Detailed Inspections – Intrusive Inspections

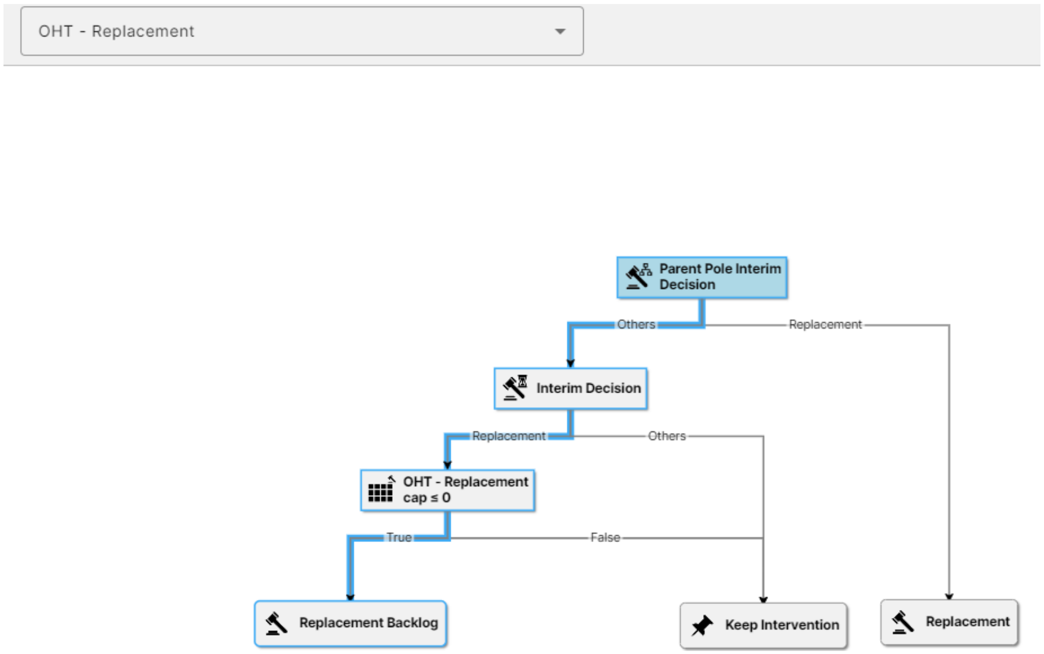
Detailed inspections and intrusive inspections for overhead transformers have not been incorporated in this current phase of the model, as the decision logic has not been defined by BVES.

Replacement

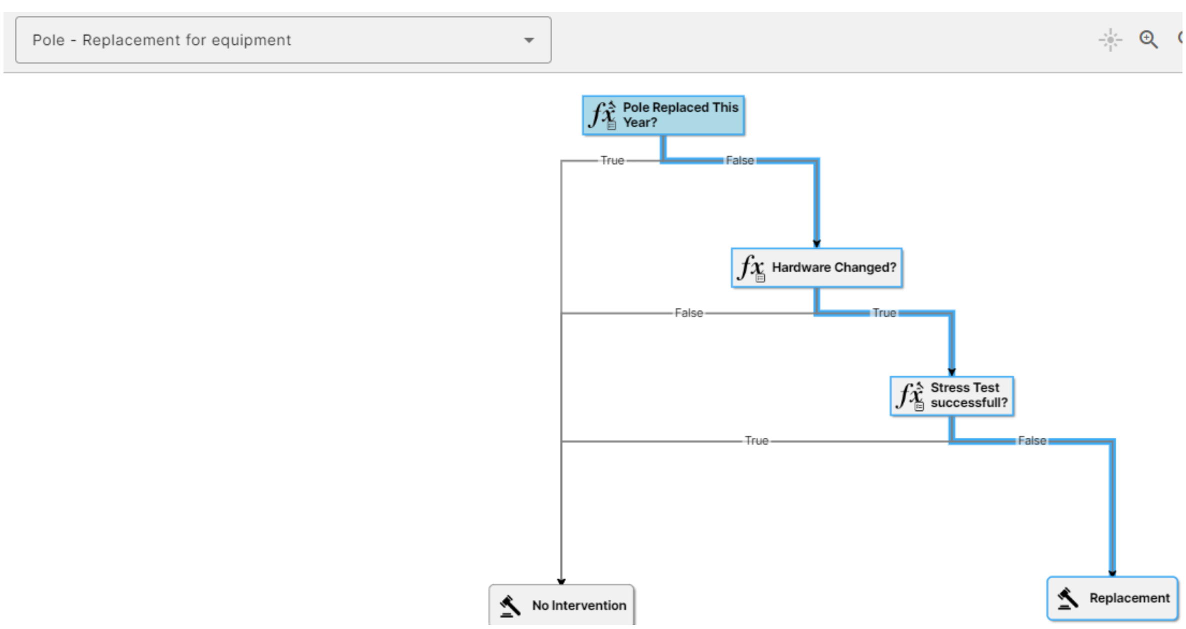
In 2030, the model triggers an end-of-life failure for Overhead Transformer T10002BV:



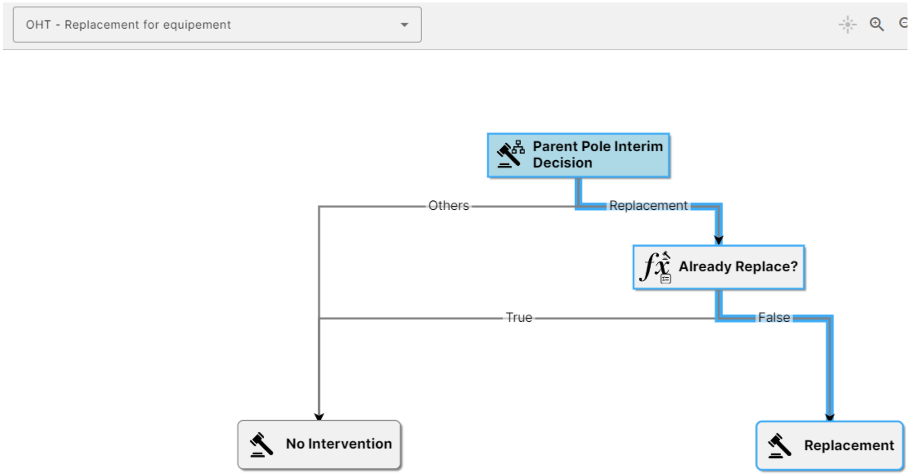
The overhead transformer replacement budget cap is set at $200,000 per year. The prioritization order is set at the circuit level according to fire risk, meaning assets within circuits with the highest average fire risk will be prioritized. before moving to the next circuit in the prioritization order. When the budget reaches below 0, assets of the remaining circuits in the priority list must wait for the following year if they need to be replaced. In this situation, the OHT replacement budget was below 0 when OHT T10002BV ran through the decision tree and was marked as Replacement Backlog.



However, the parent of OHT T10002BV, Pole 10002BV was marked for replacement as the model has triggered a failed stress test:



The decision tree considers the logic that any equipment on a pole needing replacement will also be replaced:

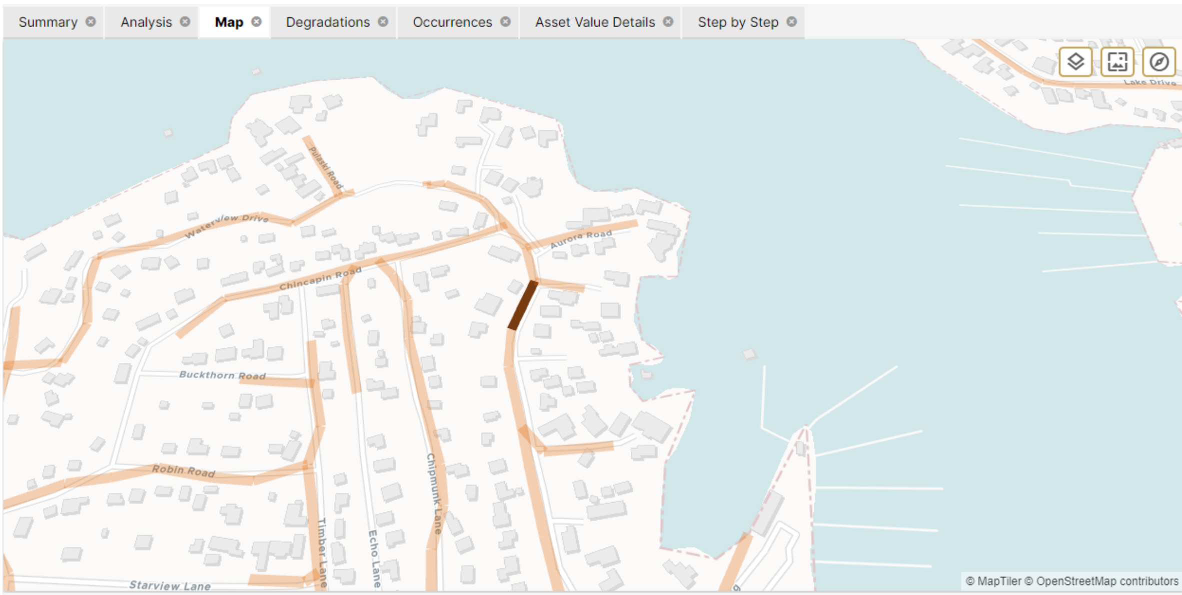


The overhead transformer replacement will reset several characteristic values (Age, Probability of Failure, Probability of Fire, CM – Overhead Transformer Failure) as well as trigger replacement costs:

Characteristic	Beginning of Step	End of Step
Age	45	0
Age Range - Map	45-50	0-5
Already Failed?	True	False
Already Replace?	False	True
B material - Cost (Constant Value)	0	1200
B material - Cost (Current Value)	0	1200
CM - Overhead Transformer Failure	1.007	1.002
Failure - Numerical	1	0
Failure?	True	False
Installation Year	1985	2030
Labor Cost (Constant Value)	0	1075
Labor Cost (Current Value)	0	1075
Number of Replacements	0	1
Probability of Failure	0.01026	0.003
Probability of Failure - Choice	5	3
Probability of failure - Score	5	3
Probability of fire - Final	0.5036	0.501
Replacement Cost Total	0	5191
Replacement Material - Cost	0	2916
Replacement Material - Cost (Current	0	2916

Overhead Conductor

This use case will follow the step-by-step journey of Overhead Conductor OH_10008 T10002BV of iteration 1 between the start of the simulation in 2023, to its replacement in 2032:



Initial Characteristics

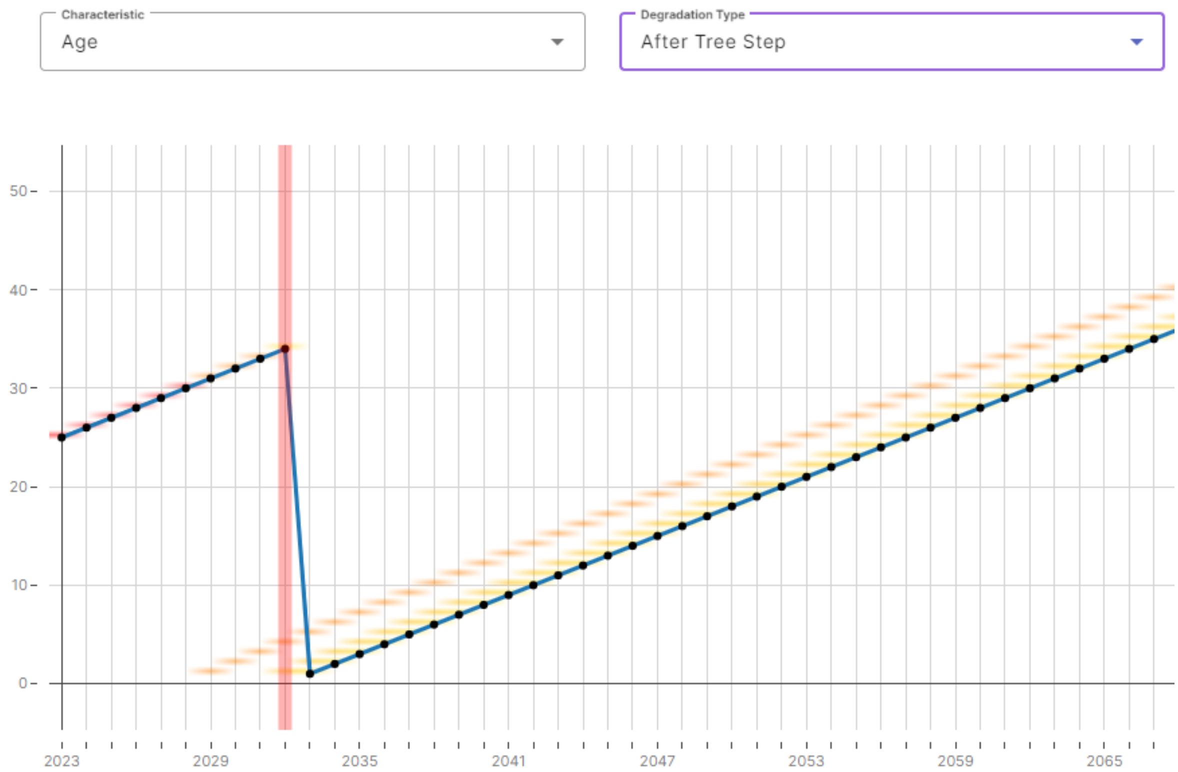
Characteristic	2022
Conductor Length	207.2
Conductor Material	Copper ...
CONDUCTORTYPE	Bare
INSTALLDATE	1998
StandardConductorOD	0.162
wmBaseKv	4.16

Asset Details

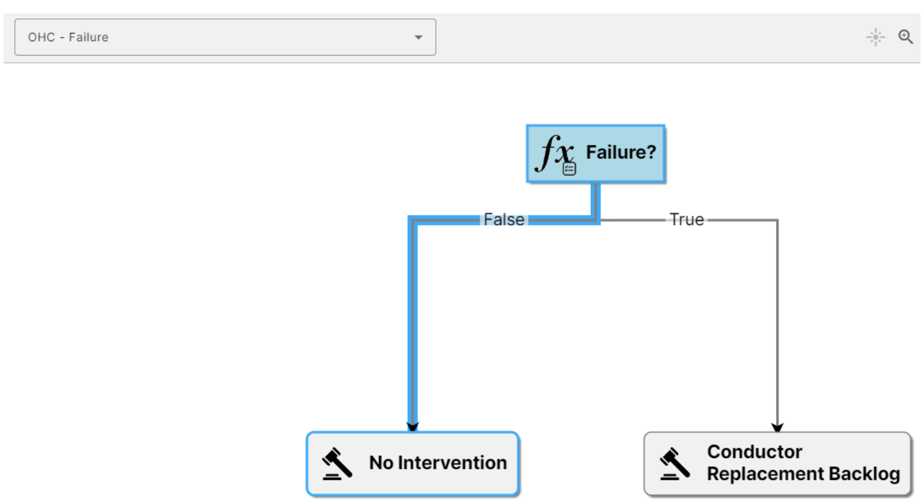
Description	OH_10008
Asset Type Importation Code	OHC
Asset Type Description	Overhead Conductor
Client Asset Code	OH_10008
ID	3045
Parent #1	Bear Valley
Parent #2	Boulder Circuit
Parent #3	2230 - D2229

Degradation

The overhead transformer is 25 years of age at the start of the simulation and ages by one year between 2023 and 2032.



Between 2023 and 2031, the model does not trigger a failure for this asset, as seen in the decision tree below:

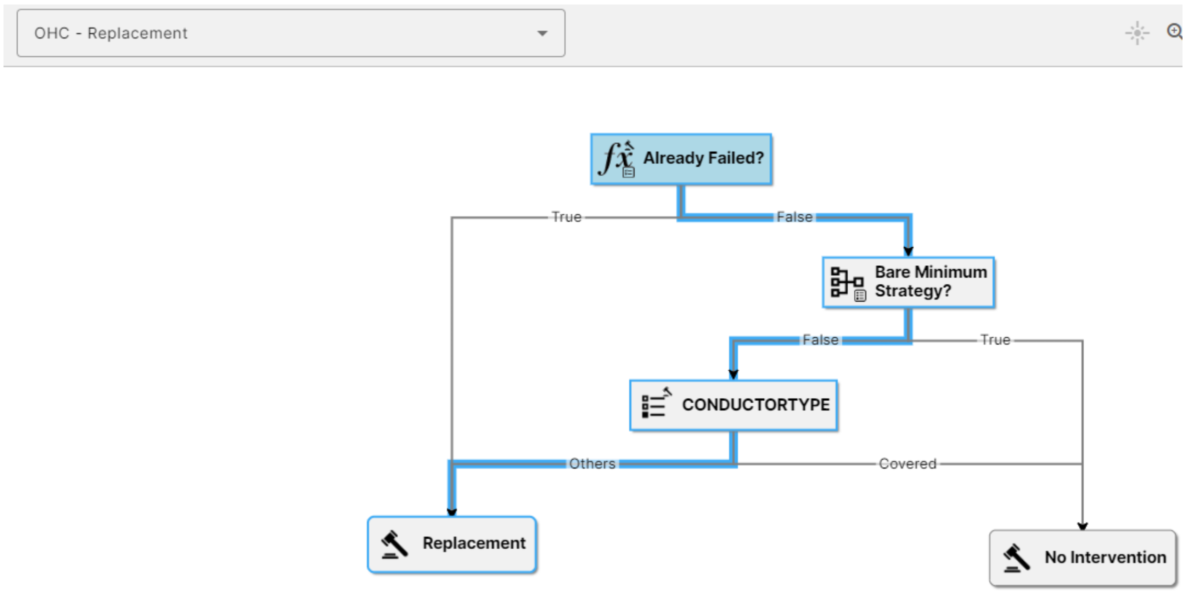


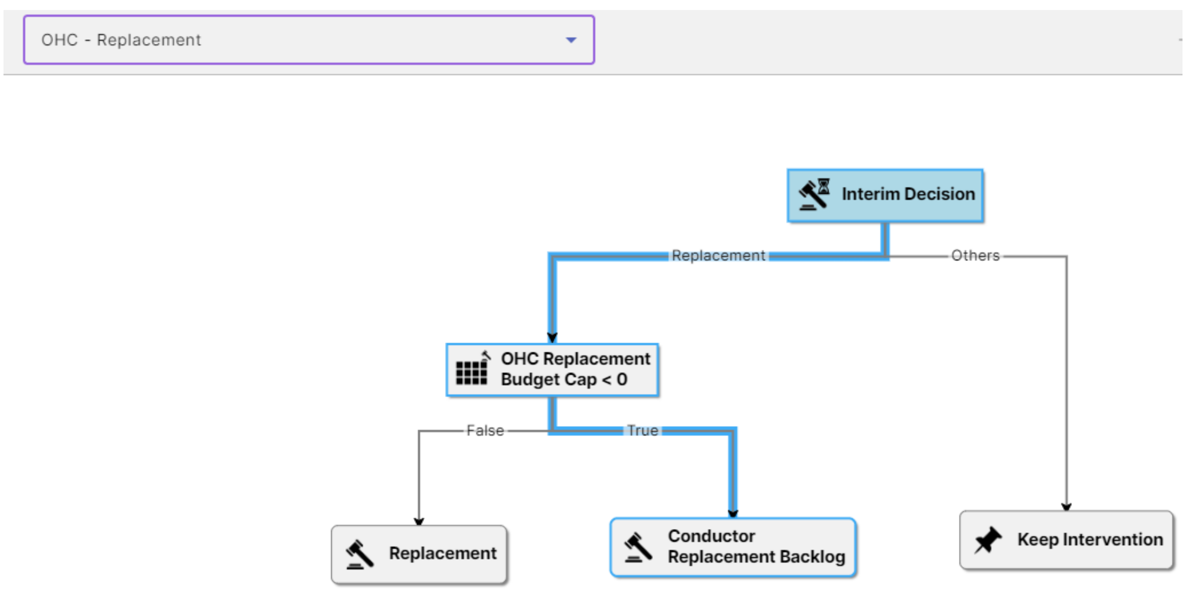
Detailed Inspections – Intrusive Inspections

Detailed inspections and intrusive inspections for overhead conductors have not been incorporated in this current phase of the model, as the decision logic has not been defined by BVES.

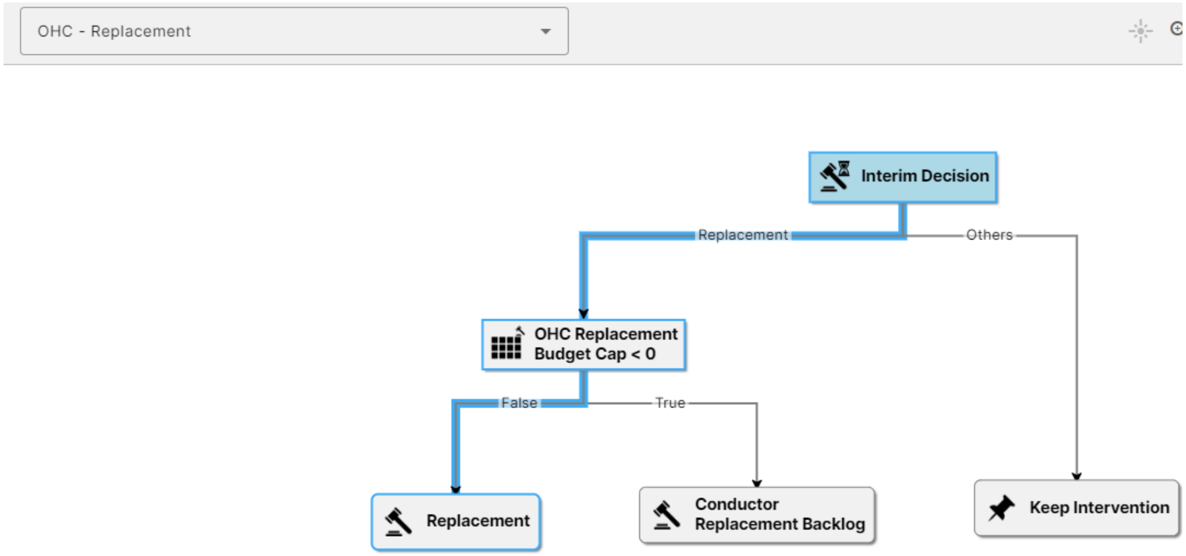
Replacement

From 2023 to 2031, no interventions are performed on OH_10008. It is a bare conductor type and although it is flagged for replacement as part of the bare to covered conductor replacement program, the replacement is delayed due to insufficient budget:





In 2032, OH_10008 is prioritized for replacement:

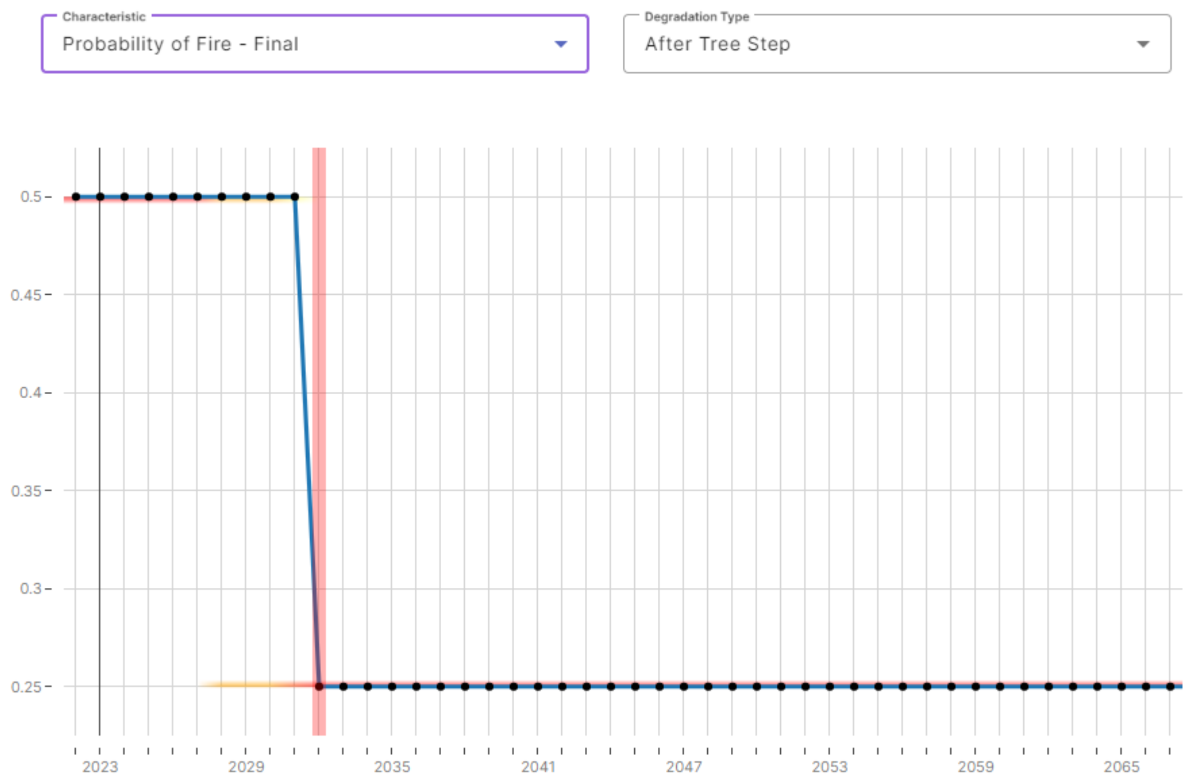


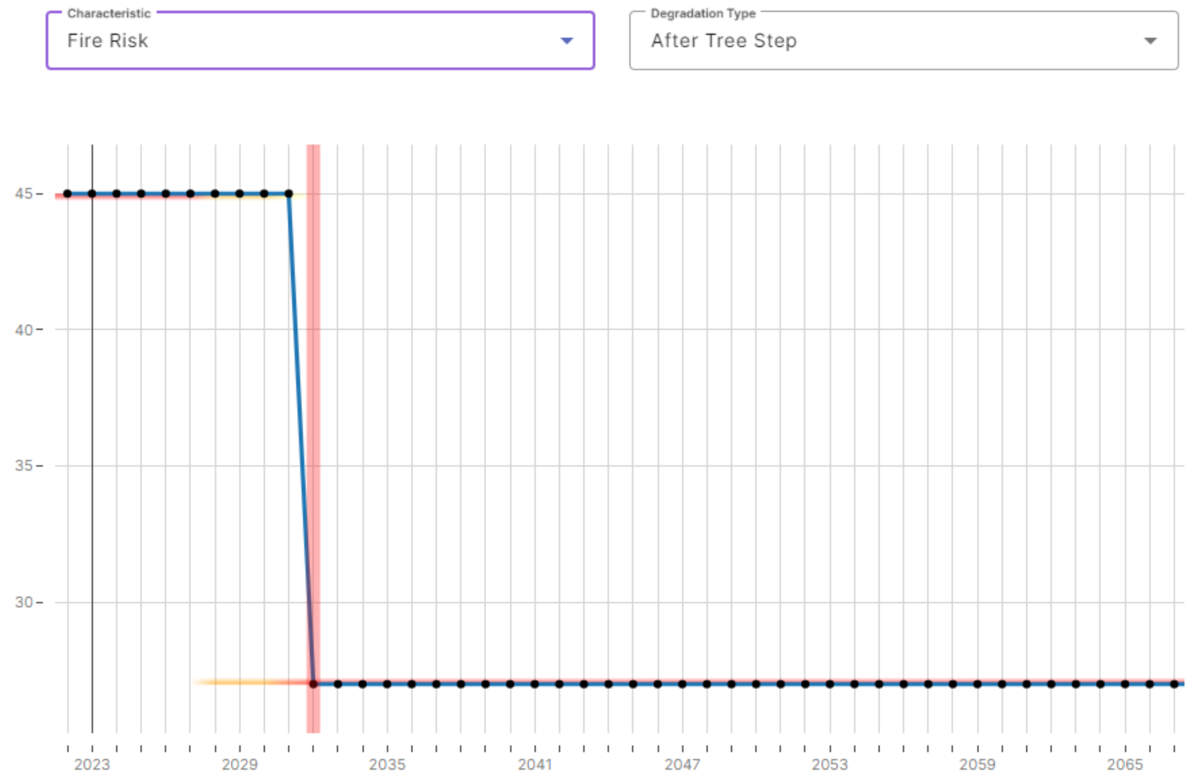
The overhead conductor replacement budget cap is set at $2,000,000 per year. The prioritization order is set at the circuit level according to fire risk, meaning assets within circuits with the highest average fire risk will be prioritized. before moving to the next circuit in the prioritization order. When the budget reaches below 0, assets of the remaining circuits in the priority list must wait for the following year if they need to be replaced. In this situation, the overhead conductor replacement budget was above 0 in 2032 when OH_10008 ran through the decision tree and was marked as Replacement.

The overhead conductor replacement will reset several characteristic values (Age, Probability of Failure, Installation year) as well as trigger replacement costs:

Characteristic	Beginning of Step	End of Step
Age	34	0
Age Range - Map	30-35	0-5
Already Failed?	True	False
CM - Conductor Type	1	0.5
CM - Final	1	0.5
Conductor Changed?	False	True
Conductor Replacement Backlog -	1	0
Conductor Replacement Backlog?	True	False
CONDUCTORTYPE	Bare	Covered
Fire Risk	45	27
Fire Risk Reduction Benefit	0	18
Fire Risk Reduction Percentage	0	22.22
INSTALLDATE	1998	2032
Number of Bare to Cover	0	1
Number of Overhead Conductor	0	1
Probability of Fire - Final	0.5	0.25
Probability of Fire - Score	5	3
Replacement Cost Total	0	3977
Replacement Labor - Cost (Constant	0	3500
Replacement Labor - Cost (Current	0	3500
Replacement Material - Cost	0	476.6
Replacement Material - Cost (Current	0	476.6
Total Cost (Constant)	0	3977

Converting a bare to a covered conductor reduces the probability of fire which, in turn, reduces the fire risk for this asset:





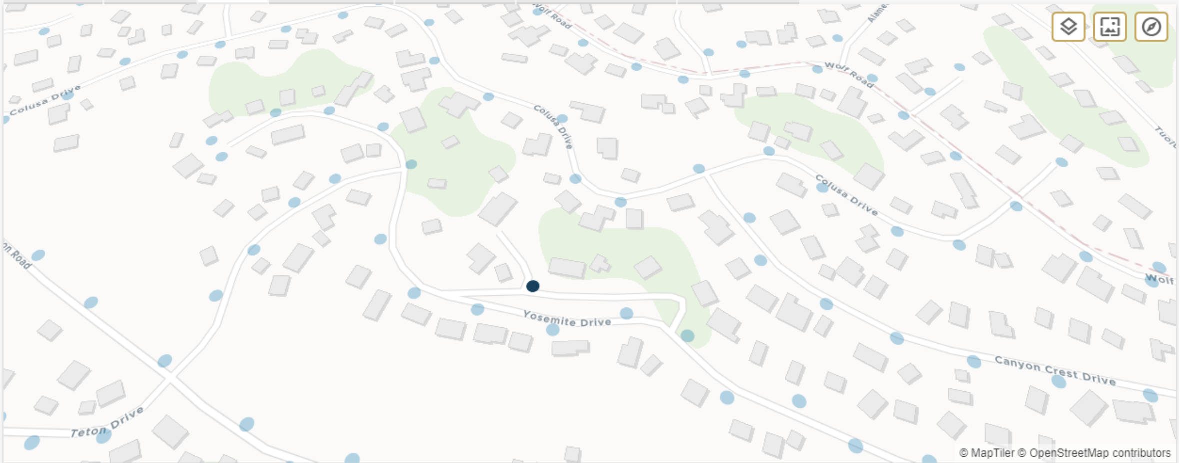
Alternative Mitigation Strategy

This use case explores the impact of replacing wooden poles with steel poles, as an alternative to fire wrapping installation in the current BVES strategy. Given that this use case impacts only poles from a risk mitigation standpoint, overhead conductors and overhead transformers will be excluded from this analysis.

Poles

This use case will follow the step-by-step journey of Pole 0593BV of iteration 1 between the start of the simulation in 2023, to its replacement in 2026:

Summary | Analysis | Map | Degradations | Occurrences | Asset Value Details | Step by Step



Initial Characteristics

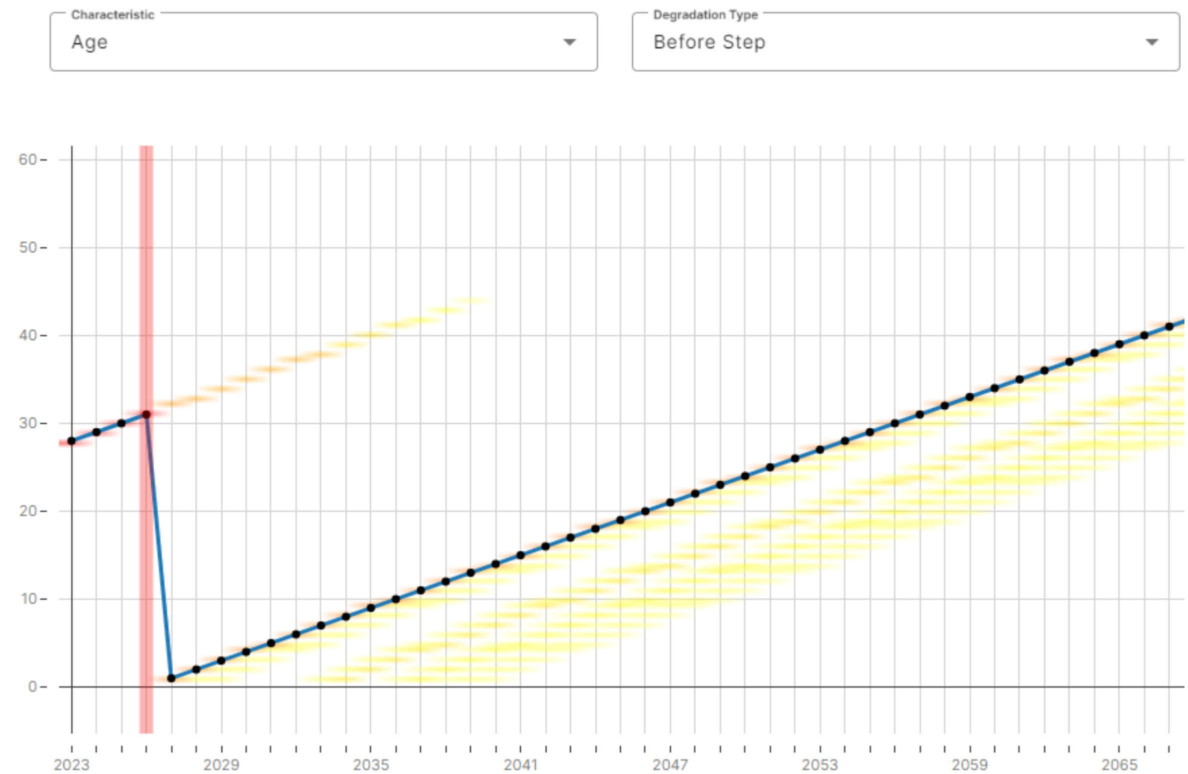
Characteristic	2022
CIRCUIT_ID	Goldmine Circuit
Fall in - Markov	Zone 2
FIRE_WRAP	False
Grow in - Markov	Zone 1
HEIGHT	35
INSTALLDATE	1995
INTINSP_INSPECT_DT	2011
Major Route?	N/A
MATERIAL	Wood
Tree Density	Medium

Asset Details

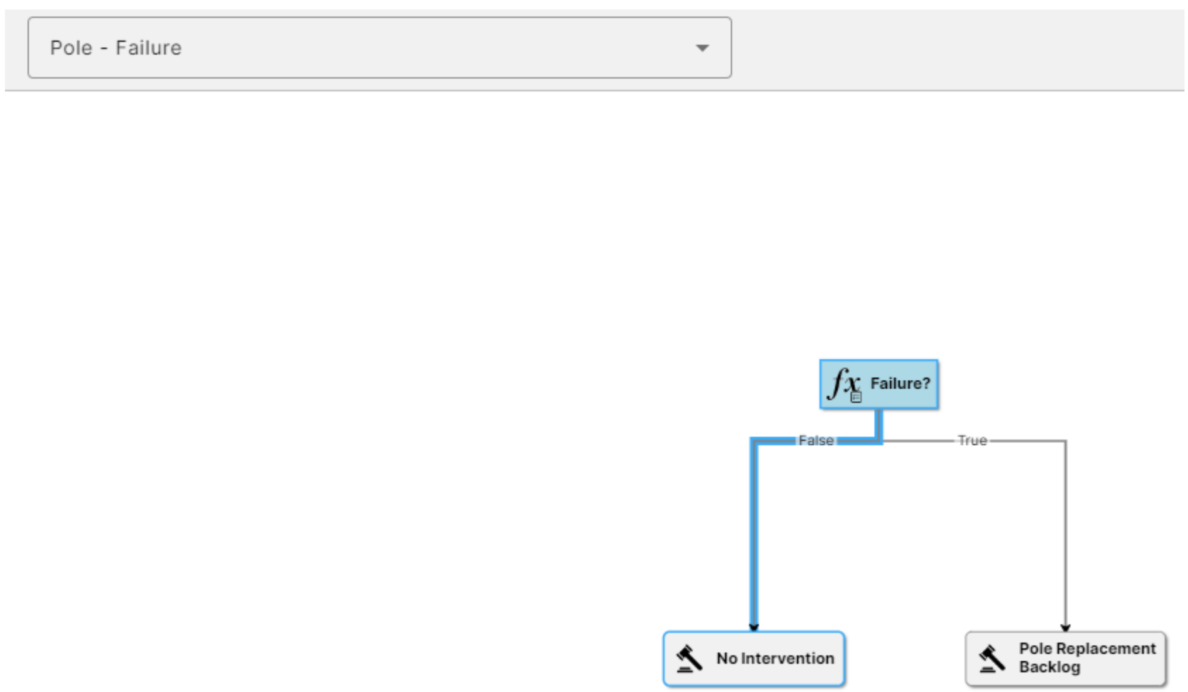
Description	POL - 0593BV
Asset Type Importation Code	POL
Asset Type Description	Pole
Client Asset Code	
ID	5397
Parent #1	Bear Valley
Parent #2	Goldmine Circuit
Parent #3	4365 - D4364

Degradation

The pole is 28 years of age at the start of the simulation and ages by one year between 2023 and 2026.

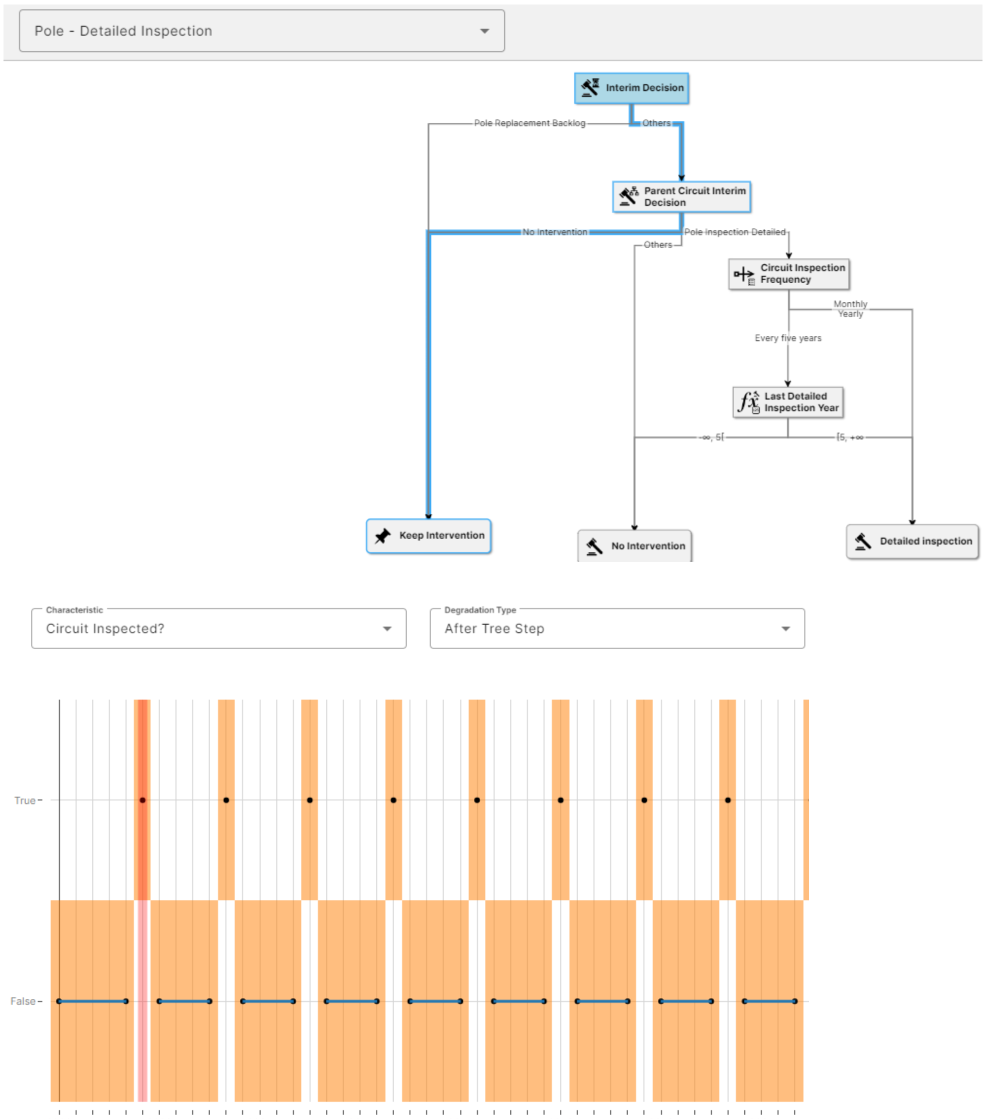


Between 2023 and 2025, the model does not trigger a failure for this asset, as seen in the decision tree below:



Detailed Inspections

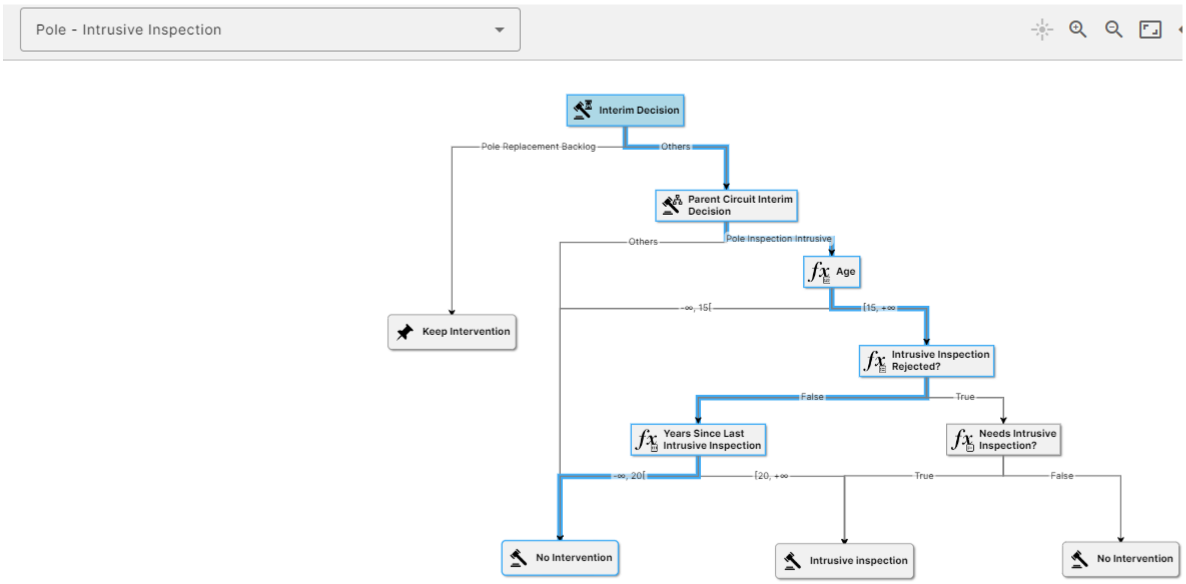
Given that inspection cycle frequencies are set at the circuit level, the decision tree must validate whether the parent circuit of Pole 0593BV, Goldmine Circuit, is triggered for detailed inspection. Between 2023 and 2027, no detailed inspections take place on Goldmine Circuit, as this circuit is set on a 5-year cycle starting in 2028:

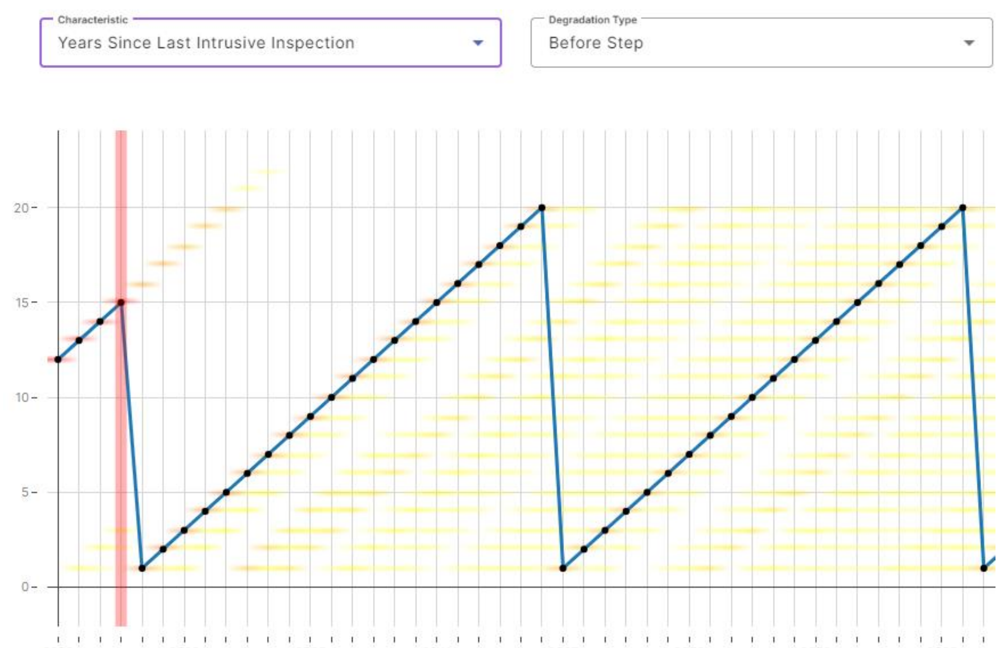


Intrusive Inspections

Intrusive inspection cycle frequencies are set at the pole level, but the information is brought to the parent circuit level to optimize the prioritization of interventions. In other words, if a pole is marked for intrusive inspection – is 10 years since its previous intrusive inspection – all other poles within that circuit that meet the criteria for intrusive inspections will be inspected. In 2023, Pole 0593BV is

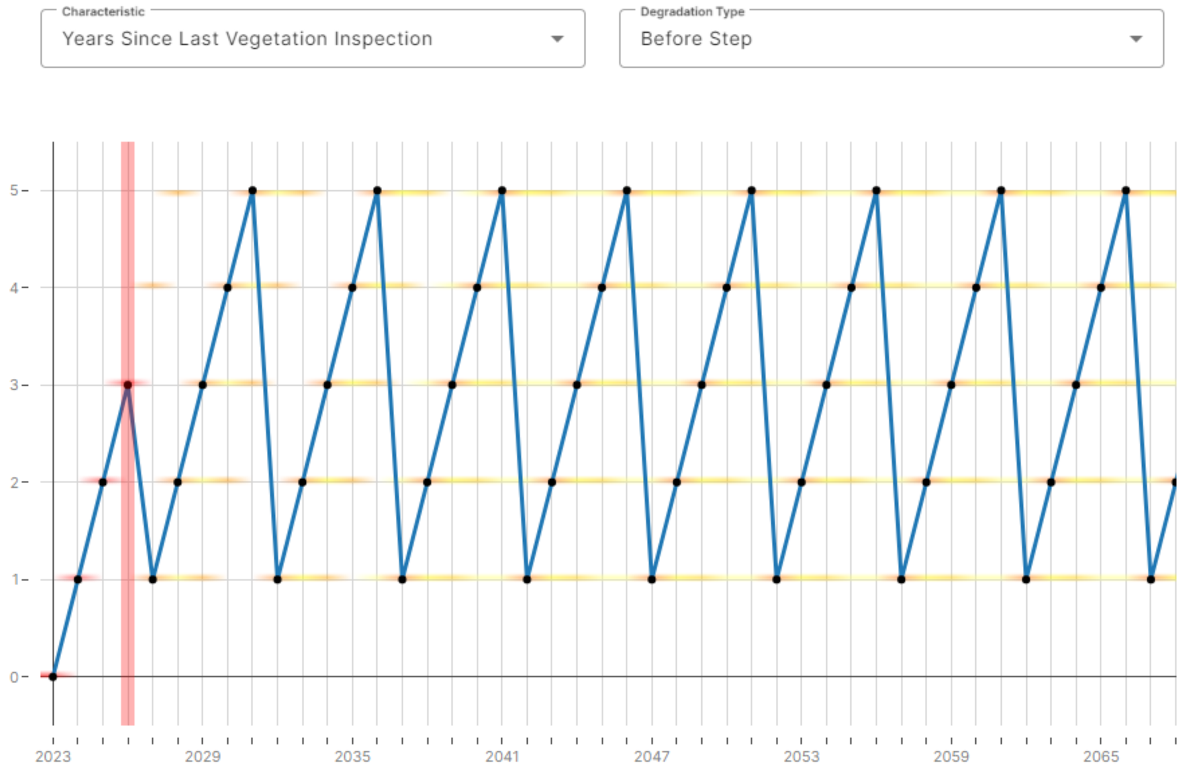
triggered for intrusive inspection, therefore all other poles within Goldmine Circuit will run through the intrusive inspection decision tree. Because Pole 0593BV is over 15 years old and the model has triggered a “Passed” status on its previous intrusive inspection, the inspection cycle is set to 20 years. The years since the pole’s last intrusive inspection is 12 years, therefore it does not require one in 2023. An intrusive inspection takes place in 2026, which coincides with the year the pole is replaced:



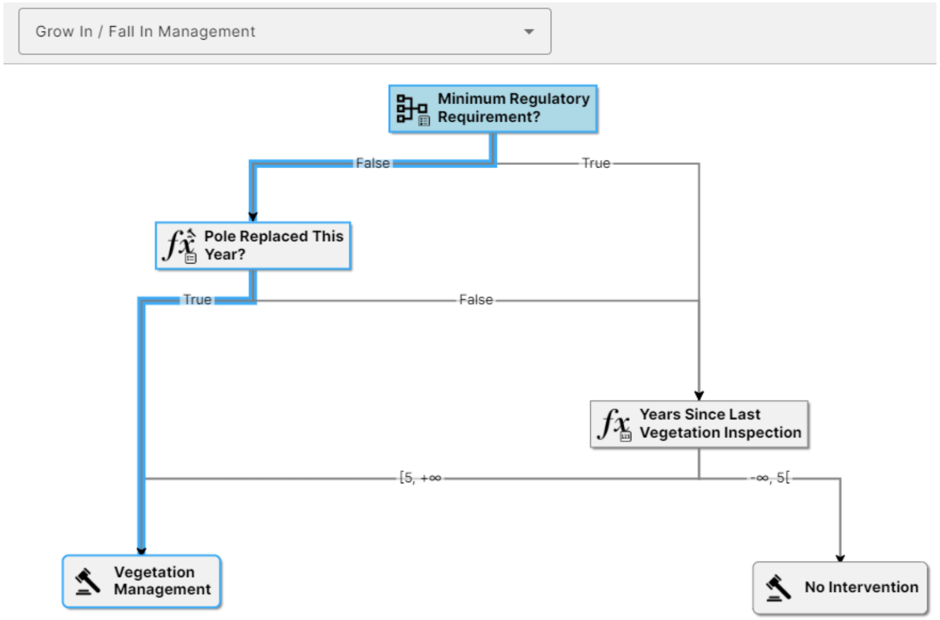


Grid Hardening

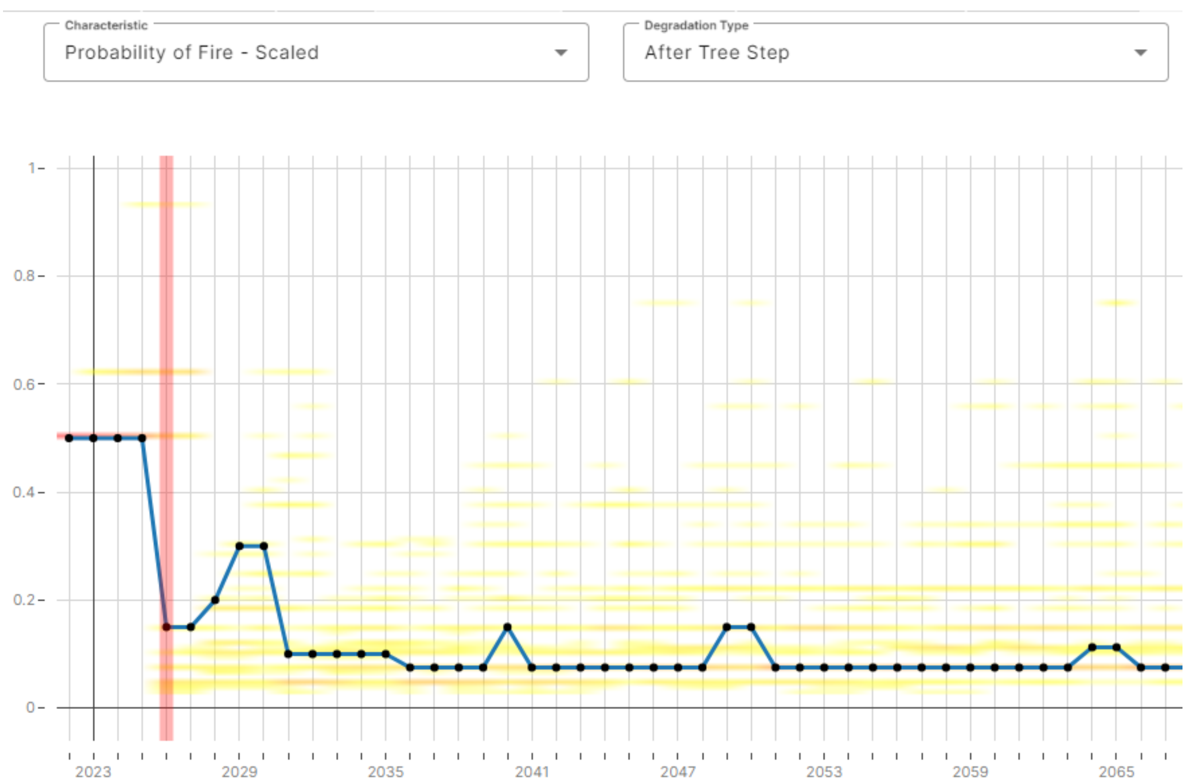
As part of the GO.165 minimum requirements, vegetation management around poles takes place every 5 years. As seen in the image below, vegetation management occurs on Pole 0593BV in 2026, which coincides with the year the pole is replaced:



The decision tree checks whether the years since the last vegetation inspection for each pole is 5 years or over or if the pole is replaced this year:

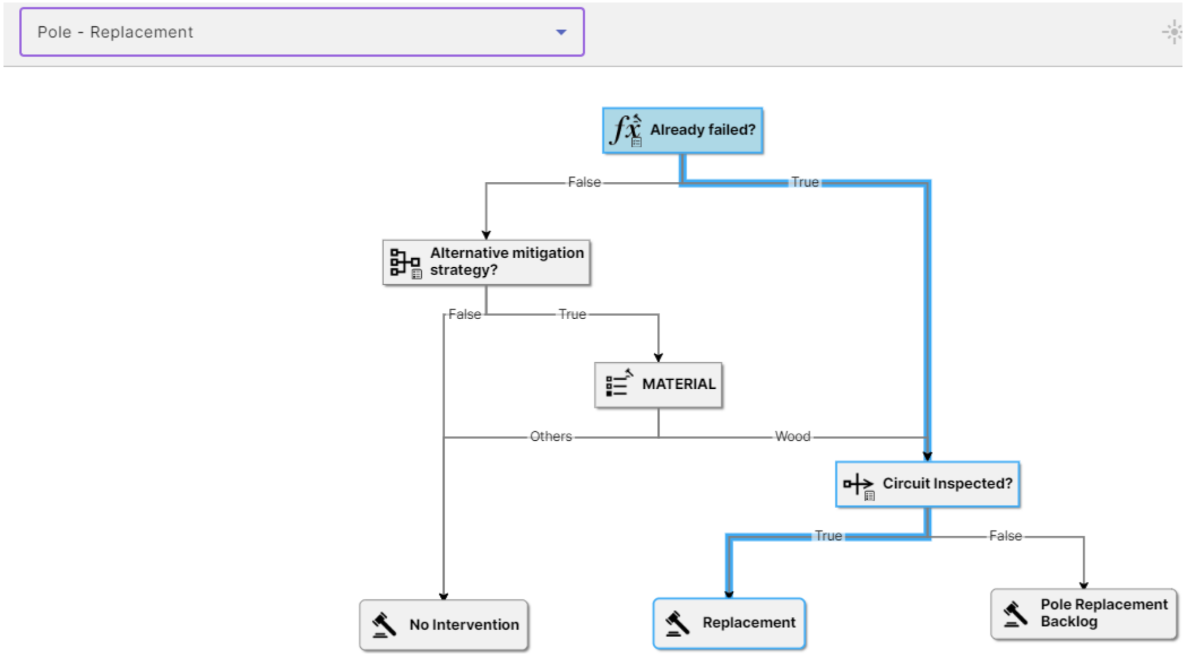


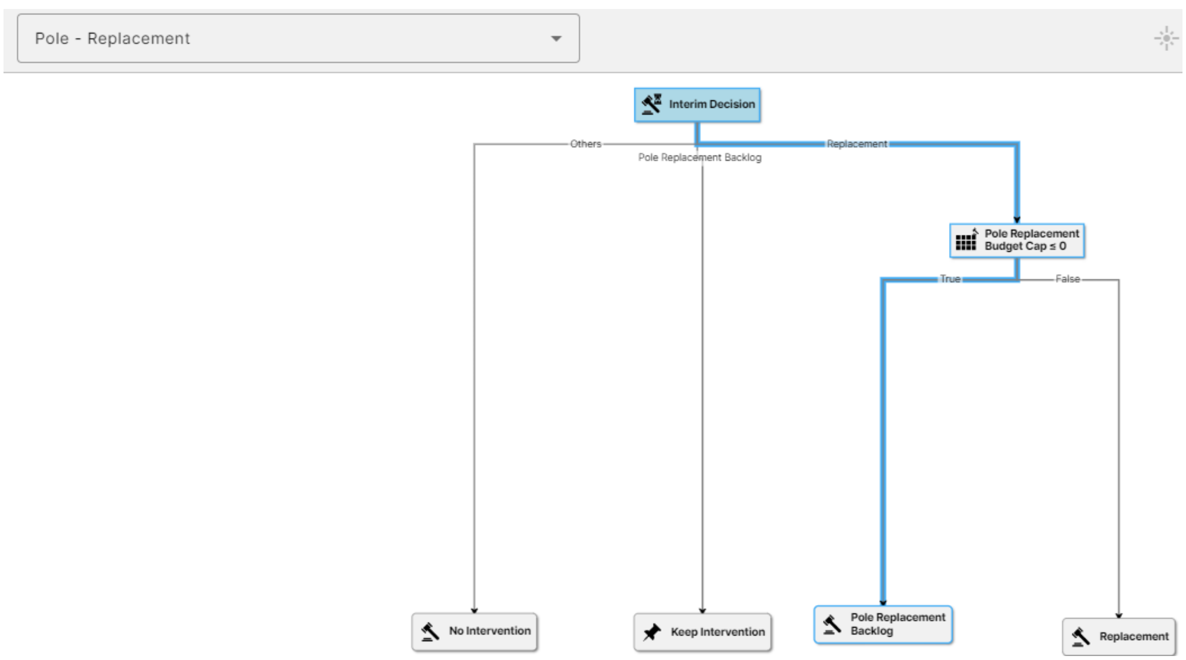
Vegetation management, coupled with a wood to steel pole replacement, have an impact on risk mitigation, as it reduces the probability of fire for this specific asset which, in turn, reduces its fire risk:



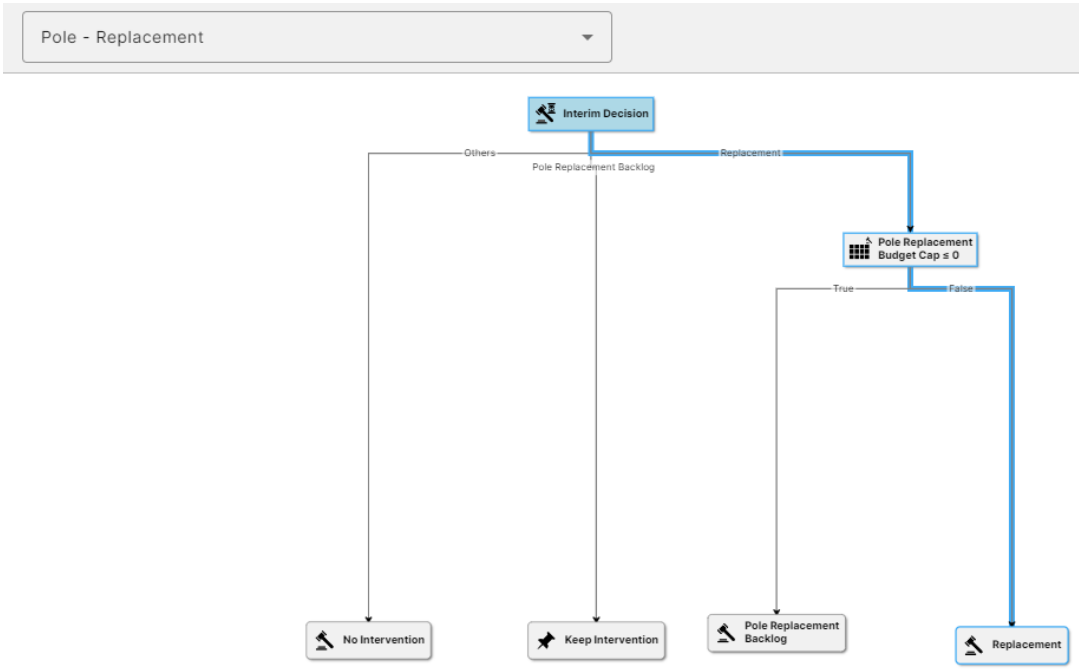
Replacement

Between 2023 and 2025, the model triggers a replacement Pole 0593BV. However, due to insufficient budget the pole is placed in the replacement backlog. Similar to the previous two uses cases, the pole replacement budget cap is set at $6,000,000 per year. The prioritization order is set at the circuit level, meaning all poles flagged for replacement within an inspected circuit will be replaced, if there is sufficient budget available, before moving to the next circuit in the prioritization order. In this situation, sufficient budget was available to replace poles in Goldmine Circuit.





In 2026, the pole replacement budget is above 0 when Pole 0593BV passes through the decision tree, which triggers a replacement:



The pole replacement will reset several characteristic values (Age, Material, Years Since Last Detailed Inspection, Years Since Last Intrusive Replacement) as well as trigger replacement costs:

Characteristic	Beginning of Step	End of Step
Age	31	0
Age Range - Map	30-35	0-5
Already failed?	True	False
Asset is replaced?	False	True
CM - Final	1.25	1
CM - Final - Min	0.04	0.05
CM - FireWrap - Min	0.8	1
CM - Pole Material	1	0.8
Fire Risk (Test)	47.25	27
Inspection Age Choice	Age-15	Age-0
INSTALLDATE	1995	2026
INTINSP_INSPECT_DT	2011	2026
Last Detailed Inspection Year	2023	2026
MATERIAL	Wood	Light Weight Steel
Minimum Probability of Fire	0.02	0.025
Needs Intrusive Inspection?	True	False
Number of Replacements	0	1
Pole Replaced This Year?	False	True
Pole Replacement Backlog - Numerical	1	0
Pole Replacement Backlog?	True	False
Probability of Fire - Final - Range	7	4
Probability of Fire - Scaled	0.625	0.5
Probability of Fire - Score (Test)	7	4

Scenarios (Technosylva dependent)

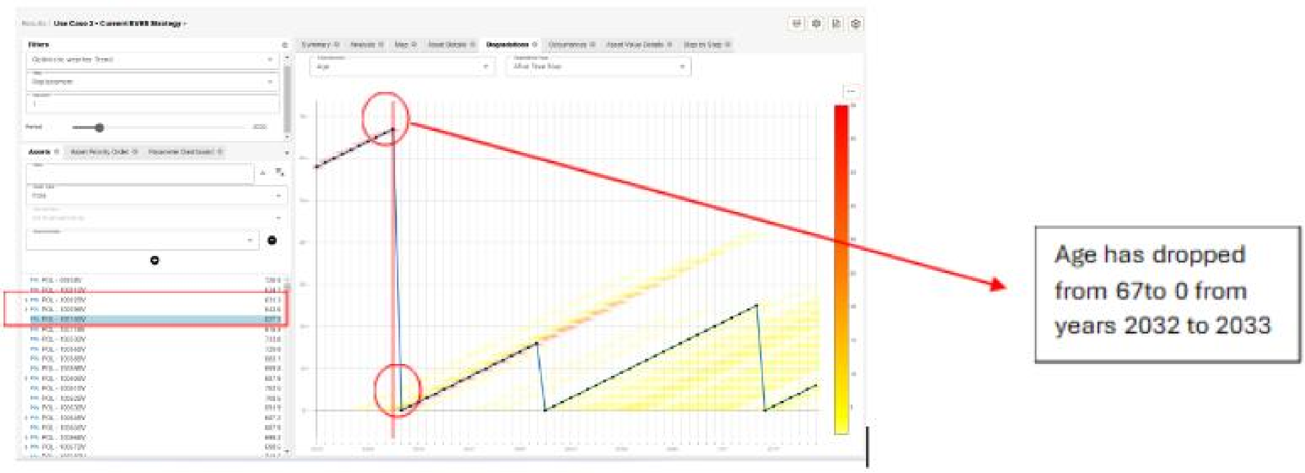
To accommodate variations in weather trends, the model defines three scenarios for each use case, allowing for a comparison of optimistic, normal, and pessimistic conditions. The 20th percentile, 50th percentile, and 80th percentile represent the conditions for each respective scenario. This approach aids the client in making well-informed decisions by considering different levels of risk tolerance corresponding to these scenarios. Looking ahead, we can enhance the model by leveraging Monte-Carlo simulations in this aspect of the model and account for uncertainties in weather trend, allowing us to explore a broader range of Technosylva-calculated percentiles. This improvement will provide a more thorough understanding of potential outcomes across different scenarios, making the model more adaptable and robust in addressing uncertainties.

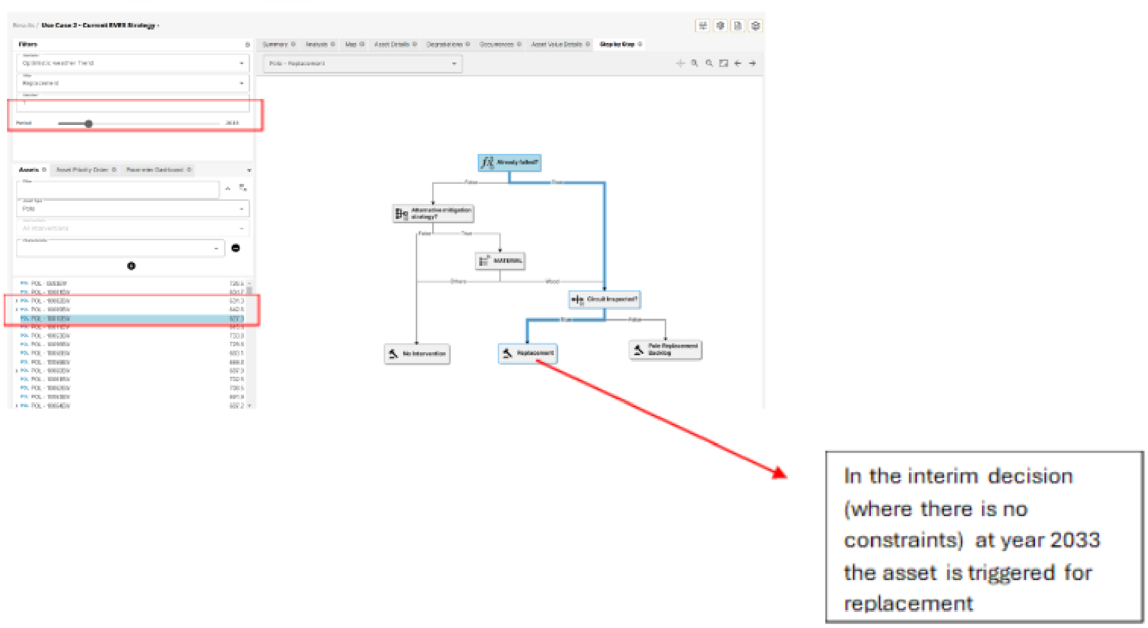
Results

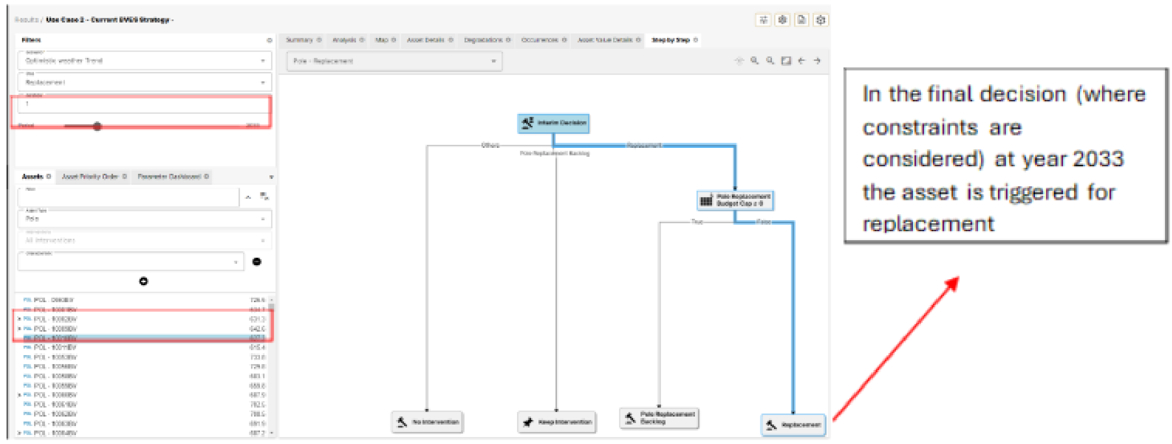
The DIREXYON suite ensures complete transparency by delivering results in two distinct formats:

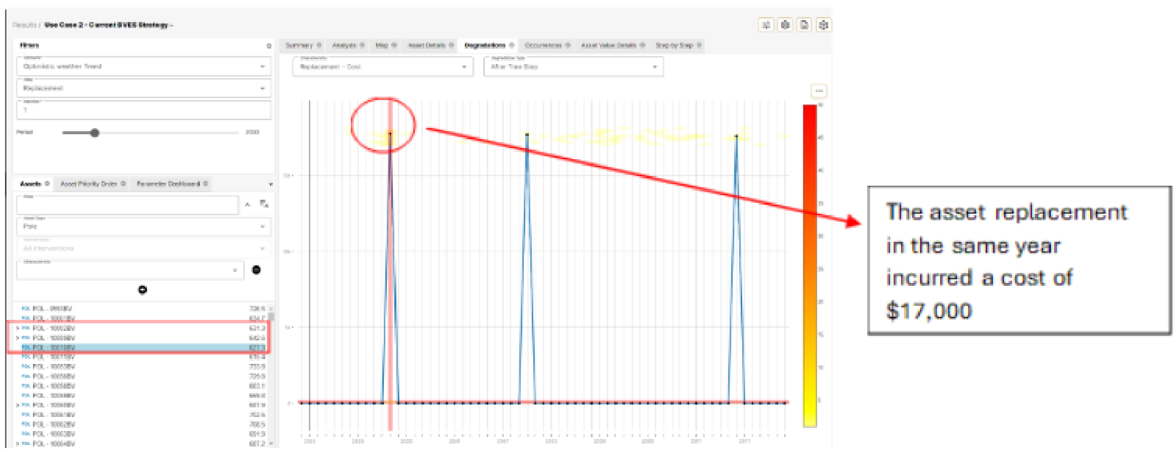
Individual Asset Level (Debug screen):

Allows you to track the journey of each asset in each year based on each iteration, verifying the evolution of asset characteristics over time. This format enables validation of specific interventions triggered at precise moments, providing insights into their impacts.









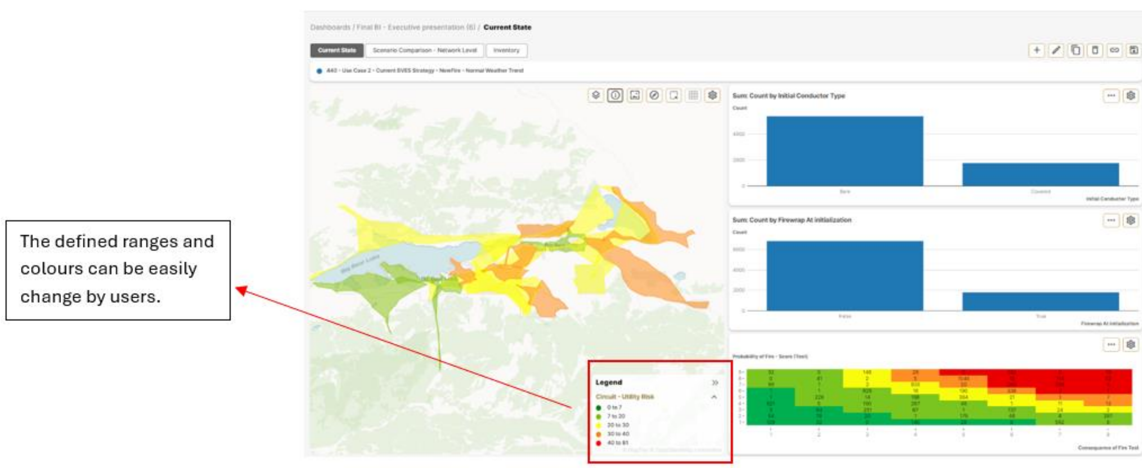
Based on the analysis results for asset POL – 10010BV, observing the age evolution reveals a decline to zero by the year 2033. At this juncture, an intervention should be initiated to address the age of the asset. Upon closer examination, navigating through the step-by-step process unveils that the asset has indeed failed. With available budgetary resources, the intervention involves replacing the asset in the same year. The consequential impact of this intervention is twofold: a triggered cost and the restoration of the age, which had dropped to zero. The provided example serves as a simplified showcase of the functionality, and all specified characteristics for each individual asset can be monitored through the debug screen.

Aggregated Results (BI dashboard):

Presents simulation outcomes in an aggregated format, offering a holistic view of the overall network condition, required investments, and other key performance indicators at a collective level. This format facilitates a comprehensive evaluation of the network's overall health and performance. The integrated dashboard within the DIREXYON suite offers versatile views, tailored to cater to various personas such as executives, asset managers, and more. These views can seamlessly switch between detailed insights and holistic overviews, providing a customized experience for different stakeholders.

Current State Dashboard:

The presented screenshot illustrates the current status of assets derived from the client's inventory. Users can effortlessly modify the predefined ranges and colors. This view offers clients insights into the current condition of the network, highlighting details such as the count of uncovered conductors and poles without fire wrap. Armed with this information, clients can strategize and plan to address these elements in the future.

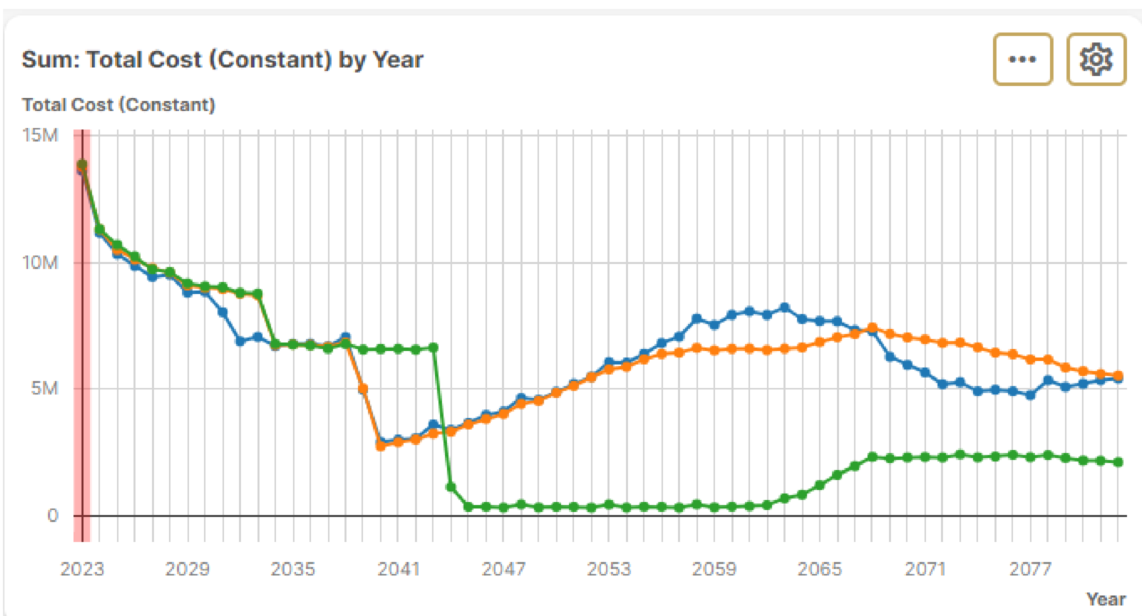


Scenario comparison Dashboard:

The presented screenshots offer a comparative analysis of different investment strategies and their short-term and long-term impacts on the network's condition. Users can utilize this view to assess and compare various investment strategies, their required levels of investment, and their effects on key performance indicators (KPIs) of the network.

Scenario comparison – Total Cost:

The attached screenshot compares three different strategies for spending on infrastructure to manage fire risk.



Use Case 1 - GO165 Minimum Requirements: This use case operates under a set of structured assumptions focusing on inspection and maintenance schedules to manage fire risk and infrastructure integrity:

- The strategy is built around maximum allowable inspection cycle lengths for poles, with intrusive inspections scheduled every ten years for poles over 15 years old, complemented by annual patrol inspections and detailed inspections based on the condition and risk profile of each circuit, which can range from yearly to every five years.

- Asset replacement is reactive, triggered by failures as predicted by established failure curves, and vegetation management is a key component of the fire risk reduction strategy, occurring every five years.

This scenario, while being more cost-effective, **relies primarily on vegetation management** as the key strategy for **reducing fire risk**. Scheduled every five years, this systematic approach helps manage the risk to some extent. However, the limited frequency and scope of vegetation management may not fully address the comprehensive fire risk, especially in areas prone to rapid regrowth or in high-risk fire zones. The cost savings in this use case are significant, reflecting a more reactive and compliance-focused approach.

Use Case 2 - Current BVES Strategy: The second use case includes not only more frequent and extensive vegetation management but also the installation of fire wraps on poles and the proactive replacement of conductors scenario. By choosing to invest in comprehensive fire prevention methods like fire-resistant wraps and safer conductors, the upfront costs are higher.

Use Case 3 - Proactive Steel Pole Replacement: Use Case 3 introduces a different strategy from the previous two, involving the proactive replacement of wood poles with steel poles with the expectation that it will lead to major cost savings over time. Steel poles, being more durable and less prone to fire suggests an understanding that some significant early investments will lead to a smoother financial road ahead, with much lower maintenance requirements. It's a forward-thinking strategy that anticipates less frequent interventions and long-term resilience.

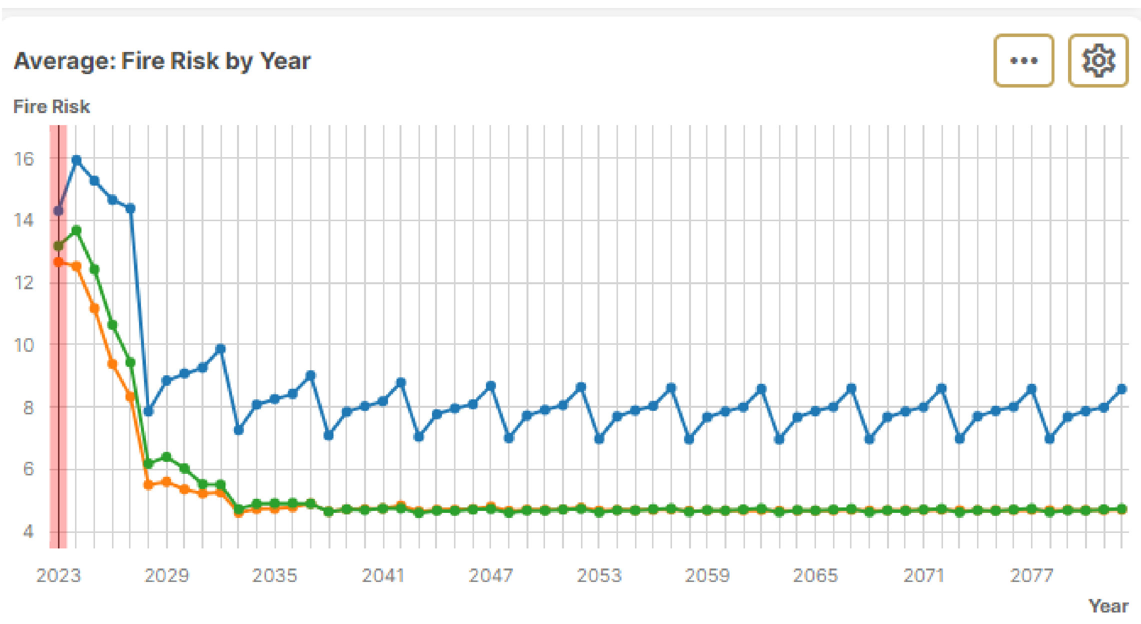
The following paragraphs compare the financial aspects of these use cases in different timeframes.

- **Initial Impact (2023 to 2029):** All three scenarios start with high costs that drop sharply within the first few years. This initial investment phase is similar across the board, indicative of upfront costs likely associated with aging infrastructure.
- **Mid-Term Impact (2029 to 2053):** After the initial decline, the costs in all scenarios start to diverge. The green line (Use Case 3, with steel pole replacement) shows the lowest costs during this period, suggesting that the switch to steel poles may lead to reduced maintenance and replacement costs. The orange line (Use Case 1, GO165 Minimum Requirements) sees a slight increase followed by a plateau, whereas the blue line (Use Case 2, BVES Strategy) climbs higher than Use Case 1, reflecting its more aggressive fire mitigation strategy that includes vegetation management, fire wrap installation, and conductor replacement.

- **Long-Term Impact (2053 onwards):** In the long term, the costs associated with the GO165 Minimum Requirements (orange) and the BVES Strategy (blue) become closer but then begin to separate after 2059, with the BVES Strategy trending higher overall. This suggests an ongoing cost associated with the BVES Strategy's proactive measures. Meanwhile, Use Case 3 (green) continues to show the lowest cost trajectory throughout the period, implying that the investment in steel poles, despite a potential high initial cost, may be economically beneficial over time.

Each of these strategies carries its own set of pros and cons: Use Case 1 is about minimal compliance, leading to a lower but more unpredictable cost curve; Use Case 2 suggests a willingness to invest more consistently for safety and stability; and Use Case 3 aims for a significant upfront investment that could result in the lowest long-term costs. Decision-makers would have to weigh these options against their tolerance for upfront costs, long-term financial planning, and their overall approach to risk management.

Scenario comparison – Fire Risk:



The fire risk graph supports the previously discussed cost implications of each use case by illustrating the effectiveness of their respective fire risk mitigation strategies over time.

Use Case 1 - GO165 Minimum Requirements (Orange Line): The fire risk in this scenario decreases sharply at first, similar to the other strategies, but then experiences variability, with the risk level stabilizing but showing slight increases and fluctuations over the years. This pattern justifies the moderate cost structure seen in Use Case 1, where spending is controlled and follows a reactive maintenance approach. The higher risk levels compared to Use Case 2 and Use Case 3 indicate that while the costs are contained, so is the effectiveness of the risk mitigation over time.

Use Case 2 - Current BVES Strategy (Blue Line): This scenario shows a significant and rapid decrease in fire risk, which then levels out to a very low and stable line. The persistent low fire risk correlates with the higher costs over time observed in the cost graph for Use Case 2, supporting the strategy's ongoing investment in aggressive fire mitigation measures such as vegetation management and infrastructure upgrades. The graph demonstrates the success of these measures in maintaining a low fire risk consistently over the long term.

Use Case 3 - Proactive Steel Pole Replacement (Green Line): Use Case 3 shows the most dramatic and sustained decrease in fire risk, dropping to the lowest level among the three scenarios and maintaining that level throughout the period. This substantial reduction in fire risk aligns with the cost graph where, after the initial investment, Use Case 3 maintains the lowest costs. This justifies the initial high cost of replacing wooden poles with steel poles, as the strategy not only results in decreased maintenance and replacement needs but also significantly lowers the fire risk.

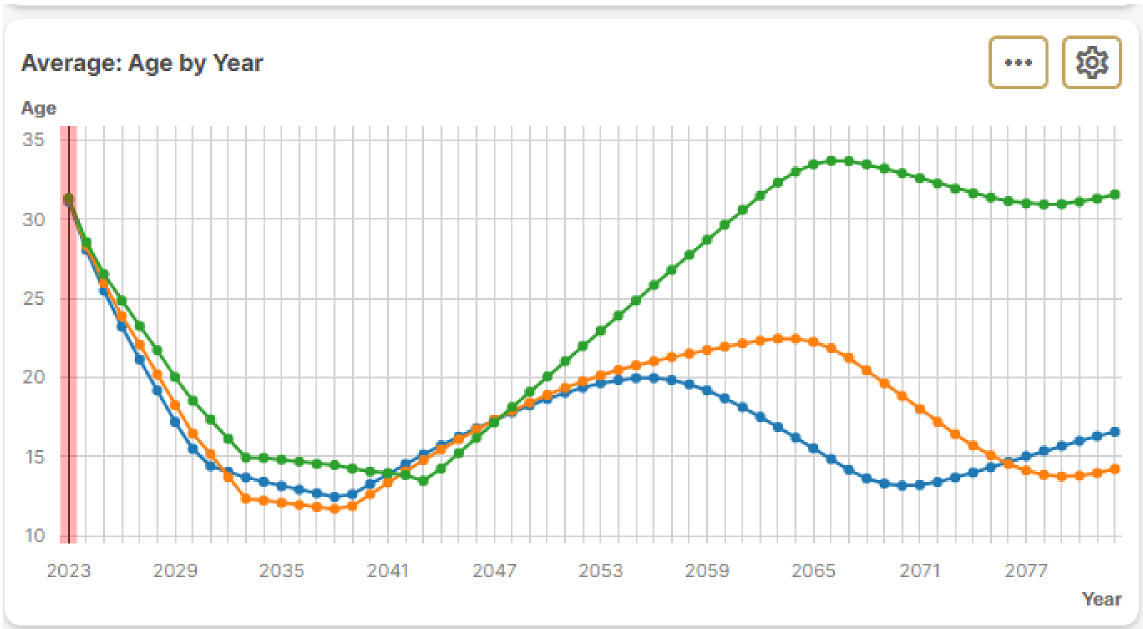
In summary, the additional investment in the BVES Strategy in comparison to minimum GO165 requirements appears justified when considering the significantly lower fire risk achieved. The approach of integrating various mitigation measures ensures that fire risk is not only reduced but is also maintained at a minimal level consistently over the years. This proactive and multifaceted strategy illustrates the principle that a slightly higher, but steady, investment in comprehensive fire risk mitigation can lead to a disproportionately large and sustained benefit in risk reduction. When comparing Use Case 3 with the other two scenarios, it presents an interesting middle ground. It potentially offers a more significant reduction in fire risk than Use Case 1 due to the inherent fire-resistant properties of steel poles. Compared to Use Case 2, while the investment in steel poles may be substantial upfront, it could result in lower long-term costs due to the decreased frequency of maintenance and replacements.

Overall, while Use Case 1 offers a cost-effective approach relying on periodic vegetation management and compliance with inspection cycles, it may result in a higher fire risk due to less frequent mitigation actions. Use Case 2 requires higher investment in extensive vegetation management, fire wrap installations, and proactive conductor replacements, leading to a substantially lower and more stable fire risk. Use Case 3, with the proactive replacement of wood poles with longer-lasting steel poles, assumes a balance between upfront costs and long-term savings, potentially offering a lower fire risk and reduced need for frequent maintenance.

The choice between these strategies would depend on the value placed on upfront costs versus long-term savings and the acceptable level of fire risk management. Use Case 3's approach, which anticipates a reduced frequency of future interventions, offers an attractive investment in terms of resilience and risk reduction over the long term.

The "Average Age " graph provides valuable insight into the lifespan of infrastructure within each use case, reflecting the relationship between the age of assets, the level of investment in maintenance and upgrades, and the implications for long-term cost efficiency and risk management.

Scenario comparison – Average Age:



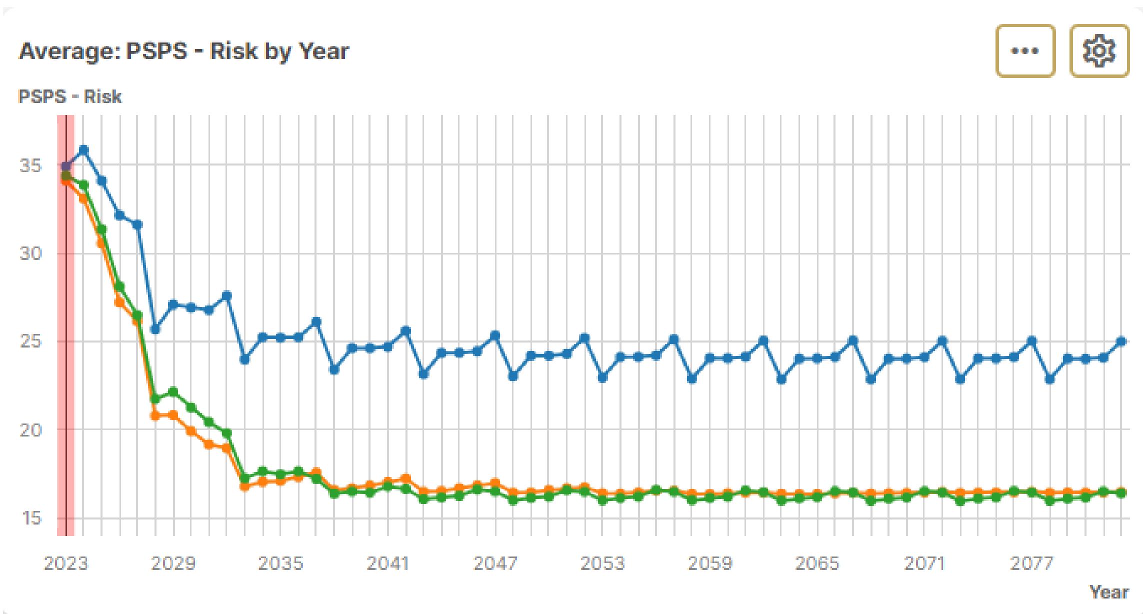
The initial decrease in average age across all three scenarios suggests a common period of heavy investment in new infrastructure, which corresponds with the high upfront costs seen earlier. After this initial phase, the strategies begin to show their long-term effects:

- The orange line (Use Case 1) demonstrates a rebound in the average age, reflecting a maintenance strategy that allows for aging infrastructure until replacement is required by failure or regulation. This mirrors the moderate but fluctuating costs associated with Use Case 1, where investment is timed with maintenance schedules and replacements due to aging components, which also contributes to the slight variability in fire risk.
- The blue line (Use Case 2) shows a more controlled trend in the average age, which levels off after an initial increase. This pattern suggests a consistent investment in upgrading infrastructure, aligning with the higher costs of the BVES Strategy. This consistent renewal of infrastructure helps maintain a low and stable fire risk.
- The green line (Use Case 3), after the steep decline in average age, maintains the lowest average age for a prolonged period before a gradual increase, indicating that the initial

investment in long-lasting steel poles leads to a lasting youthful infrastructure profile. The lower long-term costs and minimal fire risk in Use Case 3 reinforce the effectiveness of this strategy in providing both economic and safety benefits, as less frequent replacements are needed, and the younger infrastructure inherently carries a lower risk.

Overall, the age of infrastructure directly reflects the investment strategies employed. Higher upfront investments in durable infrastructure result in lower average ages and can lead to reduced costs and risks over time, as seen in Use Case 3. More moderate spending that follows aging assets and replaces them as needed leads to cost savings but potentially higher fire risks and average ages, as illustrated by Use Case 1. Use Case 2's approach of continuous renewal balances between maintaining a lower average age of assets and managing fire risk, though at a higher cost.

Scenario comparison – PSPS Risk:



The PSPS risk trends across the strategies illustrate how a focus on resilient infrastructure can profoundly affect the necessity and frequency of Public Safety Power Shutoffs. Investments that enhance the electrical system's resilience, such as the proactive replacement of wood poles with steel, are shown to not only lower fire risk but also reduce the reliance on PSPS as a preventative measure.

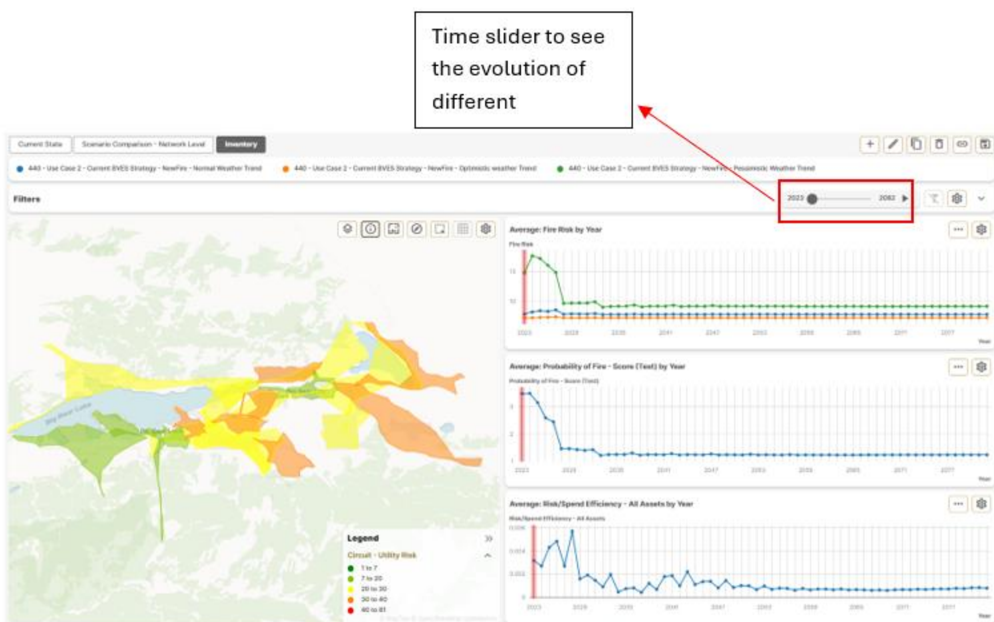
With fewer PSPS events, there's less disruption to communities and a lower risk of fire initiation from electrical equipment. This is particularly crucial for AFN customers, for whom power outages can pose serious risks. A strategy that results in a sustained low PSPS risk demonstrates a commitment to public safety and reliability, highlighting a long-term view where initial higher investments in infrastructure lead to greater stability and fewer impacts from power shutoffs.

On the other hand, a strategy that exhibits a more variable PSPS risk may reflect a more reactive approach, focusing on regulatory compliance rather than pre-emptive upgrades. Such an approach may lead to cost savings but could result in a higher likelihood of power shutoffs and, consequently, a greater impact on vulnerable populations.

In summary, the comparison of these strategies underscores the importance of resilient infrastructure in mitigating fire risk and minimizing the need for PSPS. A robust, proactive approach to infrastructure maintenance and upgrades not only ensures a safer, more reliable power supply but also serves as a critical protective measure for all, particularly for those most in need of consistent power.

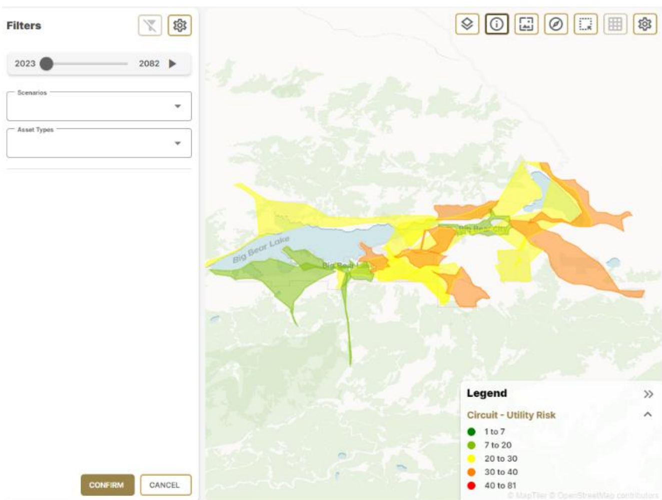
Inventory Dashboard:

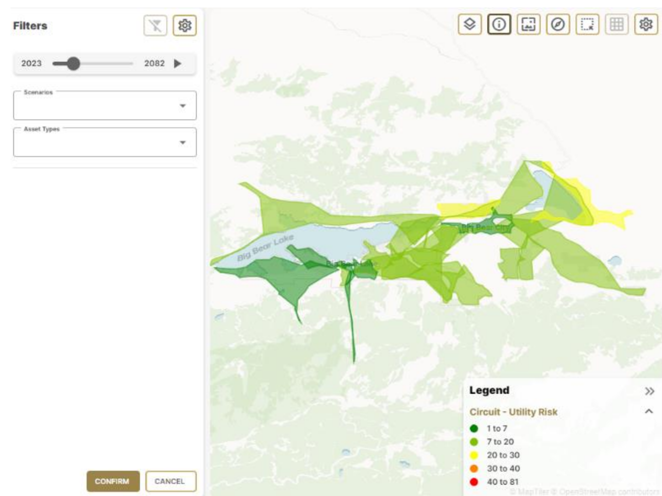
The screenshot provides a high-level overview of a utility network's risk management under the current BVES strategy across varying weather conditions. It shows the geographical distribution of risk levels across circuits, trends in fire risk over time, and the effectiveness of mitigation strategies in reducing fire incidents. Additionally, it assesses the cost efficiency of investments in risk mitigation.



Inventory Dashboard – Map:

Comparing the two maps under the current BVES strategy, we see a clear transition in the utility risk associated with the network's circuits over time. Initially, the circuits display a range of risk levels, with many in the yellow to orange zones, indicating moderate to high utility risk. However, as we move forward in time, there's a visible shift towards more circuits falling into the green zone.



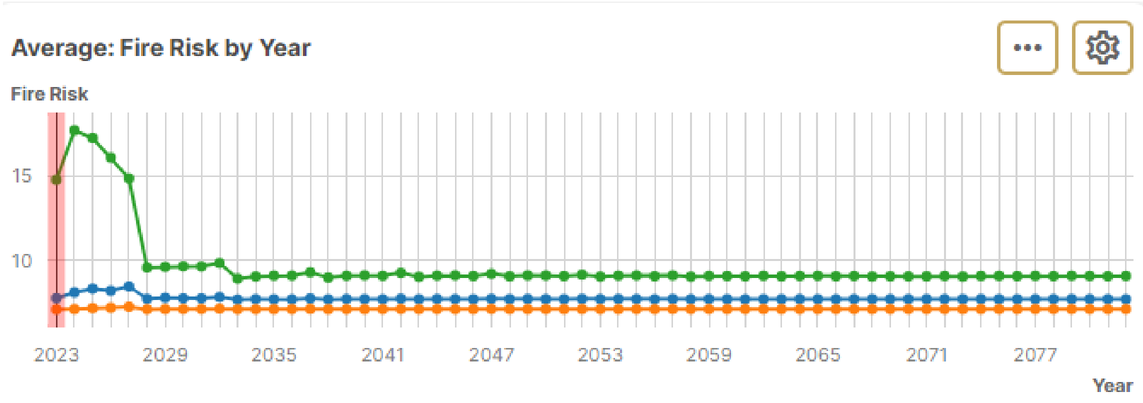


This progression towards green signifies that, over time, the current BVES strategy's mitigation measures are taking effect, reducing the overall utility risk across the network. It's an illustration of how proactive management and investment can lead to tangible improvements in the safety and reliability of the utility infrastructure.

By utilizing the time slider feature, users can observe the impact of the BVES strategy, watching as higher-risk areas (initially in yellow and orange) transition to lower-risk areas (in green). This visual tool demonstrates the potential long-term benefits of the implemented mitigation strategies and the positive outcomes of sustained investment in infrastructure resilience.

Inventory Dashboard – Fire Risk:

The graph shows the performance of the current BVES strategy under three weather scenarios, demonstrating how each scenario influences the effectiveness of the strategy's fire mitigation efforts. Contrary to typical expectations, the green line represents the most challenging weather conditions yet displays the strategy's resilience with only a modest increase in fire risk over time. This indicates that even in the worst weather scenarios, the strategy is robust, effectively preventing significant escalations in fire risk.

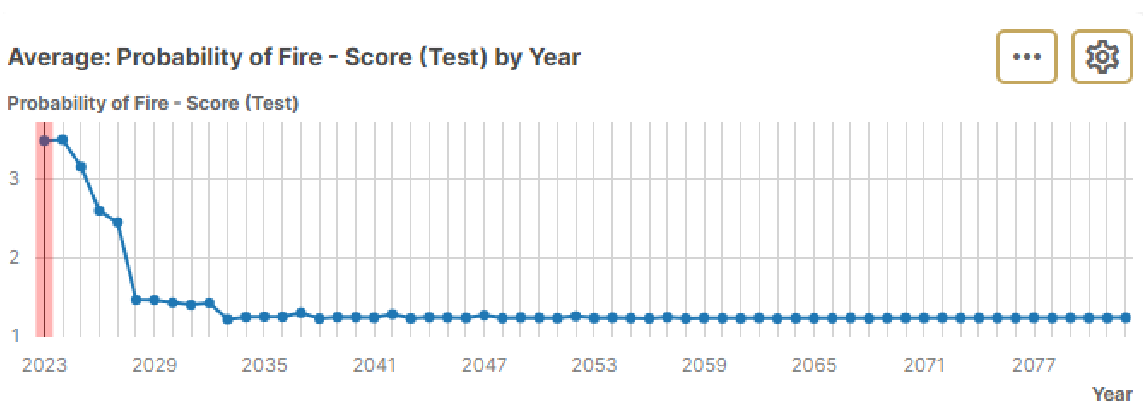


The orange line, starting with the lowest initial risk, shows a relatively stable trend, implying that in the most favorable weather conditions, there's **already a low baseline risk**, and the year-over-year risk reduction is less dramatic because there's less room for improvement.

The blue line indicates average weather conditions, where the risk starts higher, but the BVES strategy's mitigation efforts successfully reduce it over time, although not as low as the best-case scenario represented by the orange line. This suggests that while the strategy is effective across different scenarios, **its impact is most noticeable when there's a higher baseline risk to reduce**.

This interpretation helps clients understand the nuances of risk management: the strategy provides strong resilience in poor conditions (green line), ensures maintenance of low risk in favorable conditions (orange line), and effectively reduces risk in average conditions (blue line). It can inform clients how investments might perform across a spectrum of weather challenges and help them plan for different potential futures.

Inventory Dashboard – Probability of Fire:



This graph displays the average probability of fire over time, represented as a score that indicates what are the chances of wildfire. The sharp decrease at the beginning shows the immediate impact of implementing the BVES strategy in reducing probability of fire, which includes more frequent vegetation management, the installation of fire wraps on poles, and the replacement of bare conductors with insulated ones. These measures are directly related to reducing the risk of equipment ignition, which is a common cause of utility-related fires. However, after a certain point, the probability stabilizes, indicating that the major fire risk factors have been addressed effectively across the network. This leveling off can be attributed to the successful completion of key mitigation initiatives: all vulnerable poles have been fitted with fire wraps, which protect them from ignition and reduce the likelihood of equipment-caused fires. Simultaneously, all bare conductors have been replaced with covered ones, greatly diminishing the chances of electrical fires. Moreover, the vegetation across the network has been managed to an optimal state, significantly lowering the risk of vegetation contact ignitions.

At this stage, the fire risk has been minimized to such an extent that further reductions are not observed, reflecting the saturation point of mitigation effectiveness.

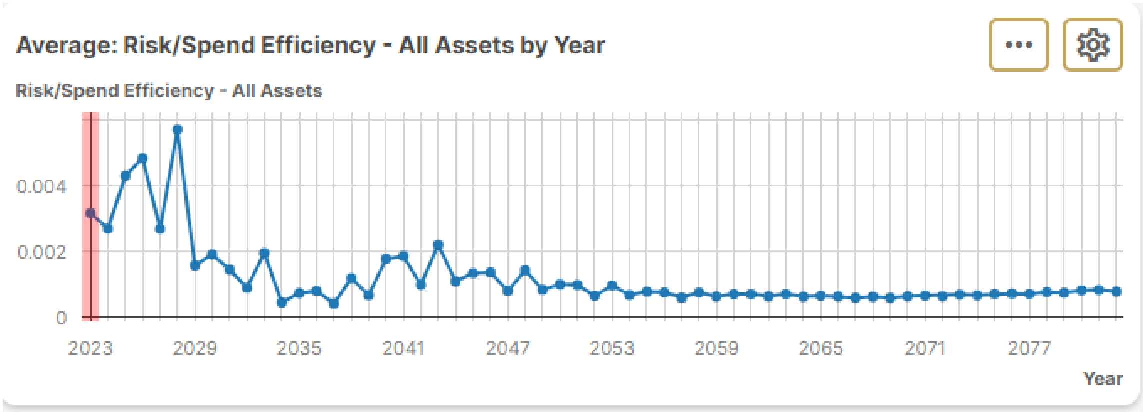
More frequent vegetation management lowers **the likelihood of contact between vegetation and electrical equipment**, which can be a significant fire starter, especially in dry conditions. By managing vegetation proactively, the probability of such contact, and hence of ignition, is greatly reduced.

The installation of fire wraps on poles is a preventive measure that reduces the **equipment's susceptibility to igniting during a fire**, thereby lowering the probability that utility assets become a source of fire.

Replacing bare conductors with covered ones significantly mitigates the risk of electrical fires. Insulated conductors are less likely to spark if contacted by tree limbs, animals, or other foreign objects, addressing the **"contact by object ignition likelihood."**

Overall, the downward trend of the graph indicates that the BVES strategy's investments in these specific fire mitigation efforts have a sustained effect on reducing the overall probability of fires in the network. This trend reflects the cumulative benefit of the strategy over time, showcasing the importance of proactive measures in maintaining a low fire risk.

Inventory Dashboard – Risk/Spend efficiency:



This chart illustrates the risk/spend efficiency for all assets over time, providing insight into how effectively the BVES strategy's investments are translating into risk reduction. The efficiency score measures the percentage of risk reduced per dollar spent.

At the start of the timeline, there's a spike in efficiency, which could be due to initial investments that significantly reduce risk. This suggests that early actions taken to mitigate fire risks, such as upgrading infrastructure or enhancing vegetation management, have a substantial impact relative to the amount spent.

Following this initial peak, the efficiency levels off and then gradually declines, indicating that while investments continue, the amount of risk reduction per dollar spent diminishes over time. This trend is expected as the most critical and effective risk reduction measures are implemented first, and as the system becomes more resilient, further investments yield smaller incremental improvements in risk reduction.

Towards the later years, the efficiency metric stabilizes at a low level. At this point, additional spending on the system may be for maintenance and minor improvements rather than large-scale risk reduction initiatives, reflecting a network that has already achieved significant risk mitigation.

Assumptions and Way Forward

In the initial phase of the project, DIREXYON addressed identified gaps within BVES 2023 WMP. For this phase, certain assumptions were made to facilitate the modeling process:

Exclusion of Inventory and Supply Chain Constraints for steel poles:

It's noted that considerations regarding inventory, supply chain constraints, and the feasibility of steel pole installation over wood poles are not factored into this analysis.

Weibull Parameters for Asset Failure

Lack of historical outage data led to the use of Weibull parameters sourced from subject matter experts or available literature to calculate the probability of asset failure. All values were corroborated with the client.

PSPS Probability Calculation:

Due to the absence of FPI data, DIREXYON utilized other available Technosylva data to calculate PSPS probabilities. The applied methodology aligns with recommendations in PG&E's 2021 guidance on PSPS.

Placeholder Weights in the Model:

The weights assigned to different fire impacts, PSPS impacts, and the participation of fire/PSPS risks in the overall risk are placeholders in the model. These values have been confirmed with subject matter experts and are subject to modification when additional information becomes available.

Scaling of Technosylva Data:

Lack of scaling in Technosylva data, combined with the varied unit measurements for fire characteristics (POI) and conditional values, prompted the use of statistical approaches to scale values. Consequently, the predicted risk scores should undergo validation through actual findings in the field before decisions are made based on DIREXYON's predicted values.

In the upcoming phase, DIREXYON recommends the following enhancements and refinements:

PSPS Model Enhancement

- Augment risk modeling by incorporating FPI Technosylva data and factoring in the monetary impact of PSPS. This includes strategies to reduce the impact on AFN customers, exploring battery storage options, and more.

Integration of Other Asset Types

- Include other asset types in the model to accommodate diverse fire mitigation strategies, such as proactive fuse replacement and assessing AFN impacts.
- Consider fire caused by different asset types and adjust the overall framework accordingly.

Vegetation Modeling as a Separate Asset:

- Model vegetation as a distinct asset, allowing for the testing of various vegetation management strategies.

Designing Additional Use Cases:

- Explore and create new use cases, testing additional what-if scenarios to further refine the model
    - Assessing the Benefits of Using Fire-Resistant conductor Materials to Replace Copper Conductors

Model Refinements:

- Utilize Monte-Carlo simulations with Technosylva data to better account for uncertainties in weather trends.
- Enhance scaling with additional insights from the client.
- Calibrate Weibull curves based on historical outage and replacement data for improved accuracy.

References

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2. https://ieeexplore.ieee.org/abstract/document/9300013/authors#authors
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DIREXYON

BEAR VALLEY ELECTRIC SERVICE

Bear Valley Electric Service

Phase 2 – Summary of Changes

February 18, 2025

Contents

Summary of changes in Phase 2:

The Phase 2 scope of work focused on expanding the model to include additional assets, refining assumptions for existing assets, updating results with refreshed data, and testing new fire mitigation strategies. The main changes to the model are listed below:

Data refresh (Completed):

All asset data related to poles, conductors, transformers, circuit inspection, population changes, and AFN customer has been refreshed. These updates incorporate the latest changes in the network, ensuring the model is fed with the most current and accurate information. As a result, the model's outputs now accurately reflect the most recent developments.

Additional Asset integration (Completed):

As part of Phase 2, new asset types (arrester and connector) were integrated into the model. The model for these assets includes decision-making strategies for replacing or removing them, while considering available constraints. This comprehensive modeling approach helps users identify the impact of each asset on risk, allowing them to focus on the strategies and assets that have the greatest potential to reduce risk effectively.

Vegetation model (In progress):

In phase 2, vegetation, previously was modeled in pole asset, is now modeled as a separate asset. More precise growth models, based on scientific research, have been established. Vegetation zones within each circuit are determined by factors such as the proximity of trees to power lines, along with key parameters like density, fall-in, and grow-in, all of which are now defined with greater accuracy. The required maintenance for each zone is estimated using historical data from BVES. This refined approach treats vegetation as an independent component, enabling users to evaluate various vegetation management strategies and assess their impact on risk evolution.

Risk model Update (Completed):

As part of Phase 2 model improvements, which included the addition of new assets and the separate modeling of vegetation, the risk model has been updated. In Phase 1, the risk of all assets was consolidated at the pole level as Condition Modifier (CM) – Equipment, and the overall risk of the network was determined based on pole risk. However, in the phase 2, condition modifiers for both pole-related assets (such as arresters and overhead transformers) and conductor-related assets (such as connectors) are now assigned to their respective parent assets—the pole and the conductor.

An overall CM is calculated for the pole based on **its characteristics** as well as the **condition of its associated assets (children)**. Similarly, an overall CM for the conductor is defined and weighted by the length of the conductor. These aggregated condition modifiers, along with the vegetation condition modifier, are then brought up to the **parent segment level**. At this level, they are used to calculate the risk of each segment, accounting for the segment's length.

This refined approach allows for a more accurate and comprehensive risk assessment, where the size of each segment is also considered. It also enables the generation of detailed information on the fire risk of segments, including a breakdown of the contribution of each asset type to the network's overall fire risk.

Additionally, as recommended by Technosylva, the model now uses the average percentile for the most probable future scenario instead of the 50th percentile, and the 80th percentile for the pessimistic scenario, replacing the previously used 95th percentile. This adjustment ensures a more balanced and realistic risk assessment for different future scenarios.

Portfolio output (In Progress):

The Portfolio is an additional module of DIREXYON that generates a list of recommended future projects based on available data and insights provided in different components of the model such as decision-making strategies, degradation model, and cost model. In phase 2, portfolio output will be configured in the model to generate list of future projects derived from current BVES strategy integrated in the model.

New Use Cases (In Progress):

1. **Alternative Mitigation Strategy (completed)**: The current BVES strategy is updated to account for the replacement of wood poles with light weight steel, composite, or wood poles, based on characteristics such as pole voltage and the number of phases.

2. **Additional Vegetation Management Strategies (In Progress)**: New vegetation management strategies focusing on the vegetation management cycle will be tested. The design of this use case relies on receiving insights from the client.

These use cases aim to refine the strategies further by incorporating new data and focusing on specific areas of risk mitigation.

PSPS model Update (Not Started):

With availability of operational FPI data from Technosylva, as part of Phase 2 statement of work, Probability of PSPS model will be updated to include FPI data. In Phase 1, PSPS probability was defined based on Fire behavior index (Flame length and rate of spread) and the calculated fire risk (POI * CMs) for individual assets. In this updated methodology however, **probability of PSPS** will be based on the following:

1. Catastrophic fire behavior (Flame length and rate of spread)
2. Catastrophic fire Probability
    a) Calculated fire risk in circuit level
    b) Fire Potential Index (FPI) from Technosylva

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Technosylva Statement of Confidentiality

This document has been developed by Technosylva, Inc. in support of our IOU customers for use in WMP development and submittal, and subsequent data requests. Confidential sections have been removed from this document and the remaining sections are considered non-confidential and can be shared in their entirety.

Confidential information is provided in its entirety to the customer to support their understanding of modeling and technical details employed in the subscription products used by the customer. As necessary, Technosylva will endeavor to provide additional generic descriptions for this confidential content to support customer submittal requirements when requested.

1 Technical Model Documentation

1.1 Purpose

The Office of Energy Infrastructure (OEIS) requires transparency in risk calculation methodologies supporting Wildfire Mitigation. Per the guidelines, OEIS has specific requirements for technical documentation, substantiation, and data governance of the models used in risk calculations for the WMP. This template outlines the required technical documentation and substantiation for the models, while the WMP Data Governance Framework covers the data governance requirements for the models.

1.2 Applicability

The applicability of the model documentation and governance applies to every model included in the Wildfire Mitigation Plan filed with the OEIS.

2 Technical Documentation

2.1 Problem or Function

2.1.1 Problem Modeled

Define the problem modeled for function performed by the program, for example, calculation of fire growth, smoke spread, people movement, etc.

The application of wildfire behavior modeling and risk analysis is used to quantify the potential impacts from possible electric utility infrastructure asset caused ignitions. The basis of this modeling is that not all ignitions (fires) are created equal, and each asset caused ignition can have substantially different consequence based on ignition location and related landscape characteristics.

The wildfire modeling and risk analysis derives a set of consequence metrics that quantify impacts. This includes potential acres burned, population impacted, number of buildings threatened, and estimated number of buildings destroyed. These are currently derived using an 8-hour simulation duration, based on a typical first burning period. Testing is underway to evaluate different fire durations based on suggestions in the most recent WMP Guidelines.

Technosylva's Wildfire Analyst™ (WFA) product is used to conduct the modeling, deliver modeling outputs, and monitor and visualize results with software applications.

The wildfire behavior modeling and risk analysis is applied to address two different, yet similar, scenarios. First, the modeling is used with historical re-analysis WRF weather data to support the mitigation planning process. The WFA FireSight, previously called Wildfire Risk Reduction Model (WRRM), is used to quantify risk metrics from millions of wildfire simulations using the numerous WRF weather scenarios defined. This wildfire consequence data is then combined with probability of failure and ignition analysis developed internally to define composite risk values to support prioritization decision making for asset hardening and related mitigation.

Secondly, the modeling is also used with daily WRF-based weather forecast data to calculate consequence based risk metrics for all assets as possible ignition sources to support operational requirements. Other key input datasets such as surface and canopy fuels, and live fuel moisture and dead fuel moisture, are developed daily using Machine Learning (ML) models to calculate the wildfire behavior outputs as part of the risk analysis model. Wildfire risk forecasts are derived daily, or sometimes twice daily, with a multi-day outlook on an hourly basis. This information is used as input into key decision making related to operational requirements, such as PSPS, resource allocation and deployment, field operations, etc.

Note that the Technosylva Wildfire Analyst™ product is comprised of three discrete applications – FireSim, FireRisk and FireSight. "FireRisk" is the new name for the application formerly called "FireCast". This was renamed to better meet platform functionality naming consistency. Accordingly, all references to FireRisk are identical to all functionality previously provided under the name "FireCast". Also note that the platform is now called Wildfire Analyst. "Enterprise" has been removed from the product platform name. To meet PacifiCorp requirements, a subscription to all three applications is required.[1] These include:

1. WFA FireRisk – daily asset-based risk forecasting to support operational needs, such as PSPS (previously called FireCast), including all situational awareness capabilities.
2. WFA FireSim – on-demand wildfire spread modeling to support real-time incident analysis and "what if" analysis for pending weather events to support operational needs.
3. WFA FireSight – risk analysis for assets using historical fire scenarios to ensure comprehensive understanding of asset ignition probability and consequence to support mitigation planning, such as WMP prioritization and development (previously called WRRM). FireSight includes integration of outage analytics, probability of outage/failure, and probability of ignition as well as built-in integrations to support calculations for risk reduction, mitigation effectiveness and risk spend efficiency.

FireRisk and FireSim support operational needs while FireSight supports enterprise risk management and mitigation planning needs. FireSight is implemented separately from FireRisk and FireSim.

2.2 Technical Description

2.2.1 Theoretical and Mathematical Foundations

Convey a thorough understanding of the theoretical and mathematical foundations, referencing the open literature where appropriate.

The basis of the wildfire risk modeling for electric utility assets lies in the published, proven and accepted fire science for wildfire behavior modeling. The Technosylva WFA product used to create risk metrics for both operational and planning initiatives utilizes the best-in-class fire science available. Technosylva has been able to operationalize proven wildfire behavior models and validate these models through on-going collaboration with CAL FIRE and the US Forest Service Missoula Fire Laboratory as the only unique vendor selected. This collaboration provides the operational platform to test and validate a suite of wildfire behavior and risk models that are utilized for statewide intelligence and operations by CAL FIRE, and by each IOU in California for operations and mitigation.

To support the model R&D and implementation, Technosylva regularly publishes peer reviewed and accepted articles regarding these models. Technosylva has been involved in 30+ publications over the past 24 months, with 11 as the principal investigator. Some of these publications are referenced on the Technosylva web site at https://technosylva.com/scientific-research/.

The published fire science provides the theoretical foundation for the operational models, tempered by validation analysis conducted on an on-going basis, to continually refine the models to match what occurs with observed wildfire behavior. The rest of this section provides a detailed description of the theoretical and mathematical foundation for the WFA models.

2.3 Theoretical Foundation

2.3.1 Phenomenon and Physical Laws (Model Basis)

Describe the theoretical basis of the phenomenon and the physical laws on which the model is based.

Fire is a self-sustained and usually uncontrolled sequence of processes basically carried out by the combination of fuel, oxygen and heat. In forest fires (also referred to as wildland fire or wildfire), the fuel is given by the vegetation layer composed of trees, bushes and all kinds of dead and living foliage (organic matter). The oxygen is abundantly present in the atmosphere and the heat is caused by the combustion of the flame and transported mainly by radiation and convection within the vegetation.

A quick review of the process involved could be described as follows. Consider a homogeneous flammable solid material like wood to which an external heat flux has been imposed. As the solid material absorbs the heat it raises its temperature at a rate dependent on the net heat capacity of the material (mix of all the components of the solid, including water). As the temperature increases, the moisture content in the solid diminishes and eventually dries up the solid. A further increase of the temperature causes the pyrolysis process of the wood (around 550 K), the organic material decomposes into a stream of volatile gasses (smoke, carbon and oxygen) and into solid remains like char (nearly pure carbon), and ashes (incombustible minerals like calcium, potassium, etc). The pyrolyzed fuel vapor convects and diffuses, mixing with the oxygen of the atmosphere and forming a combustible mixture. The high gas temperature favors the initiation of a gas phase combustion reaction in the combustible-oxidizer mixture. The compound molecules break apart, the atoms recombine with the oxygen to form water, carbon dioxide and some other products. The whole process is ruled by many factors, the types of char and volatile, the amount of oxygen and the exact chemical reactions taking place. The temperature difference between the gasses released in the pyrolysis process and the ambient air together with the gained temperature due to the oxidation reaction (around 1000 K), generates a buoyancy flow that raises up the hot combusting gas forming the characteristic flames of the fire.

In the wildland, fire behavior deeply depends on the vegetation (type, size and vertical arrangement), terrain, wind and moisture conditions of the vegetation (dead and living material). From a descriptive perspective, wildfires main observables are the fires Rate of Spread (ROS), flame length, flame intensity, heat per unit area, flame depth, and residence time. Depending on the behavior of the fire it may be classified as surface and crown fire. Surface fires burn loose needles, moss, lichen, herbaceous vegetation, shrubs, small trees and sampling that are at or near the surface of the ground. Crown fires burn forest canopy fuels, which include live and dead foliage/ branches, lichens in trees, and tall shrubs that lie well above the surface fuels. They are usually ignited by a surface fire. Crown fires can be passive or active. Passive crown fires involve the burning of individual trees or small groups of trees (often called torching). Active crown fires, or also referred to as running crown fires, present a solid wall of flame from the surface through the canopy fuel layers.

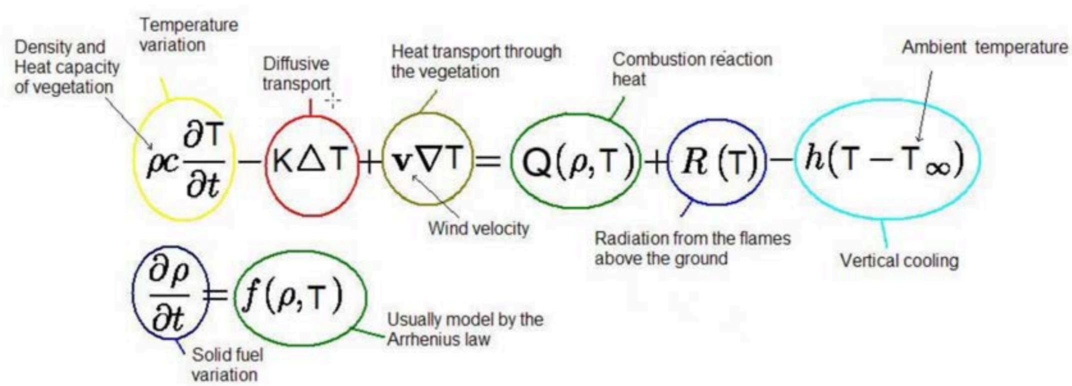
Fire growth from an ignition point can be split into four distinct phases (Fire science 2021), in the first phase the fire starts to burn slowly as the influx of air caused by the buoyancy flow of hot gasses causes the flames to tilt inwards. Once the fire has spread enough from the ignition point, wind is able to enter the already burned vegetation and pushes the flames away from the center and tilts them towards the unburned fuels, increasing the heat transfer, and therefore accelerating the fire. As the fire moves further away from the center, the acceleration of the fire depends more on the local characteristics of the curvilinear front. Finally, the fire may reach a steady-state when the fire line is uniform enough so that it can be considered of infinite length.

2.3.2 Governing Equations

Present the governing equations and the mathematical model employed.

Fire modeling is a highly challenging problem from both the physical and the numerical point of view, and consequently historical advances in this field have always been forced to a compromised position due to the desire of practical usefulness, computer capabilities, required input data, and existing numerical methods. It is only by the consideration of these requirements that the primary natural approaches to the problem can be understood. The primary broad approaches are physical models, quasi-empirical models, and empirical ones.

Physical models are the most complex and have the advantage to be more generally valid across different fuels and weather conditions (Cruz 2017). They are usually posed as a set of coupled differential equations derived from conservation laws and defined on a usually bidimensional domain representing the vegetation layer considered as a porous medium where the main variables develop. The degree of approximation of the initial semi-physical description of the problem, as well as the rest of physical effects considered in the modeling may vary greatly from one model to another. Despite these different approaches, a conventional 2D multiphase model, sketching vegetation temperature through a convection reaction diffusion equation, and a solid combustible material evolution in time may serve as a simple example for illustration purposes.



Example of a 2D multiphase model sketching vegetation temperature and solid combustible

Even though physical models are very promising, they are not easy to make operational because in many cases the detailed input data they need is not readily available, and because they require a lot of computer processing capability, as they usually use adaptive meshes to keep track of the burning front. Some numerical methods used for solving these models are the Finite Element Method (FEM), Finite Difference methods (FDM), etc.

Empirical and semi-empirical models are mainly based on experimental data: laboratory runs, controlled outdoor fires, or well documented wildland fires. The difference between the empirical and semi-empirical approach is that the former ones contain no physical basis at all and are generally statistical in nature, while the later use some form of physical framework on which the statistical model is based (Andrews 2018, Sullivan 2009). These models are largely developed to support decision making and are the main operational models used today.   They are typically able to predict the source dataset with mean absolute percent errors between 20 and 40% (Cruz et al. 2013)

Further review of existing fire modeling approaches can be found in Catchpole and De Mestre (1986), Weber (1991), Pastor et al. (2003), Sullivan (2009a,b,c)

2.3.3 Assumptions

Identify the major assumptions on which the fire model is based and any simplifying assumptions.

The following are some of major assumptions contained in the models

- The physical framework development is based on an idealized situation in steady state spread which may not fit some extreme behavior of fires.
- Fuels are assumed to be continuous and uniform for the scale of the input (typically between 10 to 30 meter (m) resolution)
- Fire characteristics at a point only depend on the conditions at that point (point-functional model). This means that there are certain non-local phenomena like:
    - o Increase of ROS due to a concave front.
    - o Fire interaction between different parts of the same fire or a different one
- Fire spread is assumed to be elliptical although there are several variations such as double ellipse, oval, egg-shape, etc.
- Weather is given hourly and is assumed to remain constant during that time. There is no interpolation in time to compute the evolution of weather between hours.
- Reliability of weather inputs in the mid-range forecast (2 to 5 days)
- Fire is not coupled with the atmosphere in any way. This may seem like a major limitation in the model as wind is a main contribution to fire spread and at present many models (specially physical ones) try to couple wind and fire. The main reasons for us not to consider the coupling is:
    - o It would make it infeasible to run millions of simulations considering the coupling effect.
    - o Empirical and semi-empirical models have been developed using an average wind speed as an input, so it is not clear that considering more granular wind at the front is advisable.
- Fire is always assumed to be fully developed. Fire acceleration, flashover, or decay is not considered.
- Atmospheric instability which may have a deep impact on ROS (beer 1991) is not considered in the model.
- Gusts are not considered in the model
- No interaction between slope and wind other than creating an effective or equivalent wind. This means that fire is assumed to have an elliptical shape no matter the alignment of wind and slope.
- Models have been developed with scarce empirical data. The abundance of today's fire data sources, however, is allowing us to better adjust models to observed fire patterns.
- Fuel array description of the vegetation may not perfectly describe fuel characteristics.
- Spotting is only considered in surface fires

2.3.4 Independent Review Results (see Guide ASTM E 1355)

Provide the results of any independent review of the theoretical basis of the model. Guide E1355 recommends a review by one or more recognized experts fully conversant with the chemistry and physics of the fire phenomena but not involved with the production of the model.

The core models implemented in WFA form the basis of most operational propagation models in use today (Andrews et al 1980, Gould 1991). They have been implemented in well-known software like NEXUS (Scott and Reinhardt 2001), Fire and Fuels Extension to Forest Vegetation Simulator (FFE-FVS) (Reinhardt and Crookston 2003), FARSITE (Finney 2004), Fuel Management Analyst (FMAPlus) (Carlton2005), FlamMap (Finney 2006) and BehavePlus (Andrews et al.2008). Nevertheless, forest fires are a very difficult phenomenon to simulate which depends on many different factors and typical simulations are able to predict the source dataset with mean absolute percent errors between 20 and 40% (Cruz et al. 2013)

One of the important facts in fire simulation is the definition of the fuel models, with analysis providing different results for different fuels and regions. For example, Sanders (2001) observed a pattern of over-prediction by FARSITE in fuel models 1,2, 5 by a large margin, moderate in fuel 10 and some underprediction for fuel model 8. Zigner et al (2020) used two case studies during strong winds revealing that FARSITE was able to successfully reconstruct the spread rate and size of wildfires when spotting was minimal. However, in situations when spotting was an important factor in rapid downslope wildfire spread, both FARSITE and FlamMap were unable to simulate realistic fire perimeters. Ross et al. (2006) used measurements from temperature sensors during prescribed burns in the Appalachian Mountains to recreate the fires and compared fire behavior simulated by FARSITE. They obtained a set of ROS adjustment factors that better represented the observed fire behavior obtaining a ROS adjustment factor of 1.5 and 2 for fuels 9 and 11 respectively, and a decreasing factor of 0.2 to the fuel type 6.

Apart from these reviews Technosylva has been constantly improving the accuracy and performance of the published fire models to better adjust the results to observed fire behavior. This includes a better definition of the fuel types, improved forecast of live fuel moisture content, modifications to the crown fire modeling initialization scheme, and automatic fire adjustment based on data assimilation techniques using ROS adjustment factor. In addition, Technosylva has implemented more than 21 additional models into the WFA platform to enhance accuracy and address known limitations of published fire models. These improvements include crown fire analysis, ember and spotting, urban / non-burnable area encroachment, consequence and impact quantification, etc. It is important to note that improvement of the fire modeling platform of choice necessitates not only improvements in mathematical algorithms but substantial improvements in the accuracy and resolution of input data sources. These work in concert to enhance the modeling and outputs to match observed and expected fire behavior. A robust operationalization of fire models requires constant and on-going research, testing, validation and implementation of both models and data sources.

2.4 Mathematical Foundation

2.4.1 Techniques, Procedures, Algorithms

Describe the mathematical techniques, procedures, and computational algorithms employed to obtain numerical solutions.

The fire propagation model in WFA is a point-punctual model where the fire characteristics at a given point (cell) only depends on the conditions at that cell (weather, terrain, vegetation). This fits well in fire simulation as most of wildfire characteristics mainly depend on local characteristics (Di Gregorio et al 2003), but excludes the effects of non-local phenomena.

The overall resolution is done using a Cellular Automata (CA) where space is discretized into cells (from 10 m to 30 m resolution), and physical quantities take on a finite set of values at each cell. The potential ROS at each cell at any time is given by the propagation models (surface and crown fire). CA models directly incorporate spatial heterogeneity in topography, fuel characteristics, and meteorological conditions, and they can easily accommodate any empirical or theoretical fire propagation mechanism, even complex ones (Collin et al. 2011)

Spotting is introduced as a random event where firebrands can be lifted and generate secondary ignition points ahead of the fire (in the direction of the wind).

The time evolution is done using a Minimum Travel Time (Fast-Marching) algorithm. This algorithm is similar to the well-known Dijkstra´s (1959) algorithm but more adapted to grids instead of the original model that uses graphs. This approach has been used with success in many forest fires propagation models like FlamMap (Finney 2002) and many others (CITES). The algorithm provides a solution of the Eikonal equation of a spreading curve subject to a given speed function ROS(**x**). This is done by searching for the fastest fire travel time along straight line transects of neighboring cells in the lattice. The number of neighboring cells considered determines the angle discretization of the spreading fire. The neighborhood or degrees of freedom, u, in WFA ranges from 8 cells (Moore neighborhood) to 32 cells.

2.4.2 References to Techniques and Algorithms

Provide references to the algorithms and numerical techniques.

The Technosylva WFA platform utilizes numerous models to address specific operational requirements. These models are integrated into an extendible platform that facilitates continued improvement as R&D advancements are made. The following table lists the primary models employed on WFA :

Model	Model Reference	Notes
Surface fire	Rothermel 1972, Albini 1976 Kitral IntecChile	WFA uses the core Rothermel model for fire propagation, however it can be configured for custom versions to support any empirical or semi empirical fire model. This has been done for different models employed in other countries, i.e. Chile, Canada, etc. In this regard, WFA platform is easily extended for use in unique geographies.
Crown Fire	Van Wagner (1977,1989,1993); Finney (1998); Scott and Reinhardt (2001)	Critical surface intensity and critical ROS for crown fire initialization. Expected ROS and flame intensity.
Time Evolution	Technosylva (Monedero, Ramirez 2011)	Fast-Marching method adapted to fire simulations. Minimum Travel Time algorithm with 32 degrees of freedom.

Model	Model Reference	Notes
High-Definition Wind	Forthoffer et al (2009)	High resolution wind model obtained through the integration of the USFS WindNinja software. Note: Technosylva is also the contractor for the USFS Missoula Fire Sciences Lab. for the on-going enhancement and customization of the WindNinja software. This provides Technosylva a unique understanding of the model science foundation and implementation approaches.
Wind Adjustment Factor	Andrews 2012	Wind speed conversion with height. Based on Albini and Baughman (1979); Baughman and Albini (1980); Rothermel (1983); Andrews (2012)
Fire Shape	Andrews 2018,	Unique ellipse based solely on the effective wind speed.
Live Moisture Content	Cardil et al.	Machine learning Algorithm based on historical NDVI weather reading
Dead Moisture Content	Nelson (2002)	
Spark Modeling	Technosylva	Ignition point displacement based on wind speed
Urban Encroachment	Technosylva 2016	Includes several variations of urban encroachment algorithms developed internally to facilitate spread of fires into non-burnable urban fuels. This incorporates a distance-based friction model. Based on research publications by NIST.
Spotting	Technosylva 2019	Surface spotting model for wind driven fires. Albini (1983a, 1983b); Chase (1984); Morris (1987)
Building Loss Factor	Technosylva (Cardil xxx)	Machine Learning algorithm taking into account building conditions. Based on historical damage inspection data on buildings affected by fires over the past 13 years

Many of these models were originally published from research by the USFS Missoula Fire Sciences Laboratory. Technosylva has implemented, and enhanced these models, in addition to developing new models. Most Technosylva custom developed models are supported by journal publications as part of our corporate R&D program. Some of these models are referenced on the Technosylva web site at https://technosylva.com/scientific-research/. Key references are provided below for many of the models employed in the WFA platform.

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2.4.3 Equations and Implementation

Present the mathematical equations in conventional terminology and show how they are implemented in the code.

Summary

The mathematical model used to simulate surface fire spread is the model developed by Rothermel (1972) with some modifications from Albini (1976) and some minor adjustments from Technosylva. It accepts the initial 13 fuel models (Anderson 1982) as well as Scott and Burgan's (2005) dynamical fuels where there is a transfer load between the herbaceous and dead classes. Among other outputs this model provides the surface fire rate of spread, flame length and flame intensity in the direction of maximum spread (head front). Crown fire is implemented using the model developed by Van Wagner (1977,1993) which computes the transition viability to crown fire, as well as the expected ROS and intensity in active crown fires. Spotting is modeled as a pseudo random event. The maximum expected spotting distance from the fire is obtained using the wind-driven model developed by (Albini 1983a; Albini 1983b; Chase 1984) and then embers are generated randomly on the front of the fire and the actual traveled distance is computed also randomly based on the maximum distance available. In this modeling there is no tracking of individual embers in the air. Wind speed profiles at different heights (2m, 10m, 20ft) are obtained through a logarithmic wind profile found in Andrews (2012). Fire is assumed to spread following an elliptical shape only dependent on the effective wind speed (Andrews 2012). The time evolution is done using a Fast-Marching method on a regularly spaced landscape grid of a Cellular Automata.

Surface Fire

The default propagation engine implemented in WFA is Rothermel's (1972) surface model with the modifications proposed by Albini (1976) and the requirements to accept Scott and Burgan (2005) fuel models. The basic equation in the model predicts the heads fire rate of spread without wind or slope:

$$R_0 = I_R \, \xi \, / \, \rho_b \varepsilon Q_{ig}$$

Here I_R is the reaction intensity (energy released rate per unit area of the fire front), ξ the propagating flux ratio, ρ_b the bulk density, ε the effective heating number, and Q_{ig} the heat of ignition. The equation is derived by applying the energy conservation to a unit volume of fuel ahead of a steadily advancing fire in a homogeneous fuel bed. In this model, the ROS may be viewed as the ratio between the heat flux received by the unburned fuel ahead of the fire (numerator) and the heat required to ignite it (denominator).

The input parameters to compute the ROS in the case of no wind or slope are the moisture content and the characteristics of the vegetation. Moisture content is given by the 1h, 10h and 100h dead moisture content, and the woody and herbaceous live moisture content. Fuels are assumed to be a mixture of different vegetation types depending on their class (dead or live) and size (less than 0.25 inch, 0.25-1 inch, 1-3 inch), with each class having different surface to volume ratio and loads. The inputs required to define a fuel type is given in the following table:

			LOAD				SAV					
Fuel	1h	10h	100h	herb	woody	1h	herb	woody	Dyn	Depth	MoistExt	heat

Table: input variables for each fuel type.

Here Dyn (dynamic) is a boolean variable to define if there should be a transfer between the herbaceous load and the dead one based on the herbaceous content. In general, SAV values (the fineness of the fuel) strongly affects the ROS and flame length of the fire, while the fuel load does not affect the rate of spread but can have a strong effect on the flame length.

The effect of wind and slope can be incorporated in the model through a couple of dimensionless parameters depending on the midflame wind speed U and the terrain angle θ:

$$ROS= R_0\ (1+\Phi_w+\ \Phi_s)$$

with

$$\Phi_s= 5.275\ \beta\text{-}0.3\ (\tan\theta)$$

$$\Phi_w= C\ {*}U^{\ B}\ (\beta\ /\ \beta_{op}\ )^{-E}$$

Where β_{op} and β are the optimum and standard packing ratios respectively, and C, B, and E are parameters depending on the surface to volume ratio σ:

$$C = 7.47 * \exp(-0.133\ \sigma^{0.55});$$

$$B = 0.02526\ \sigma^{\ 0.54}$$

$$E = 0.715 * \exp(-0.000359 * \sigma)$$

The slope and wind factors are summed together to obtain the final ROS. If they are not aligned the resultant vector defines the direction of maximum spread (which will be between the direction of wind and the direction of slope). This final slope-wind factor can also be used to compute an equivalent or effective wind speed causing the same effect as the combined effect of wind and slope. To do that we simply inverse the equation of the wind factor to obtain:

$$U_e= [\ \Phi_e\ (\beta\ /\ \beta_{op})^E\ /\ C\ ]^{-B}$$

The Rothermel model predicts fire characteristics (ROS, flame length, etc) only in the direction of maximum spread (head front) obtained from the combined effect of wind and slope. To compute the ROS in a direction different from the direction of maximum spread, and to be able to use the model in a 2D landscape it is assumed that a free burning fire perimeter from a single ignition point has an elliptical shape. There are several different approaches to compute the ellipse (or ellipses) eccentricity based on wind and slope (Albini [2], Anderson 1983 [6], Alexander, etc). The present implementation follows the equations in Andrews (2008) depending on the effective wind speed U_e in mi/h in the direction of maximum spread. The length to width ratio is given by:

$$L/W = 0\ .1+ 0.25\ U_e$$

Or equivalently the eccentricity e is given by

$$e= (Z^2 - 1)^{\ 0.5}\ /\ Z$$

so that the ROS in any direction ϕ is given by

$$ROS(\phi)=ROS\ (1\text{-}e)\ /\ (1+e)$$

One of the most important variables of fire is the amount of heat it generates as this is the main contributor to fire spread and fire severity. The amount of heat can be measured using different variables like the reaction intensity (IR), the Heat per Unit Area (HPA) or the fireline intensity. The Reaction intensity is the rate of energy release per unit area within the flaming front (with units of energy/area/time), heat per unit area is the amount of heat energy released per unit are within the flaming front (units of energy/area), fire line intensity is the rate of heat energy released per unit time per unit length of the fire front (units of energy/distance/time). Fireline intensity is independent of the depth zone and It is calculated as the product of the available fuel energy and the ROS of the fire (Byram 1959):

$$I_B = HA \cdot ROS$$

Where The heat per unit area depends on the reaction intensity of the fire (IR) and the time that the area is in the flaming front (residence time tr)

$$H_A = I_R \cdot tr = 384 \cdot I_R / \sigma$$

In this model the flame length and Byram's intensity are closely related by:

$$FL = 0.45\ I^{0.46}$$

Where the flame length is in feet and the intensity in Btu/ft/sc.

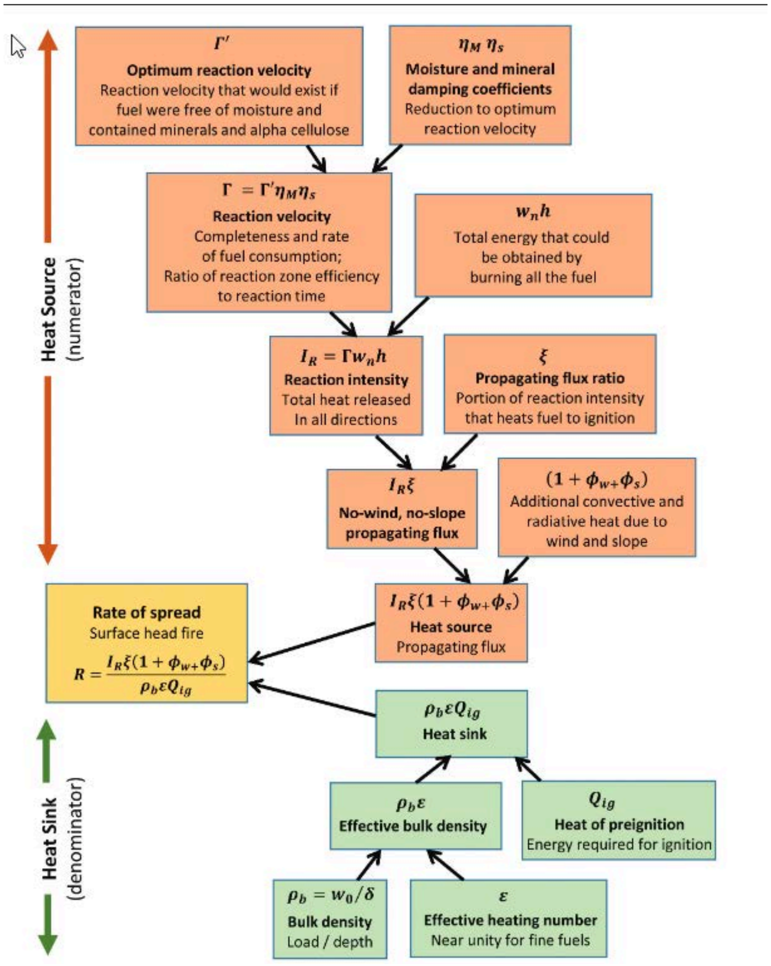


Fig X: Flow of Calculation provided in Andrews (2018)

For a much more in-depth discussion of the Rothermel surface model please read Andrews (2018) and Rothermel (1972).

Crown fire

Crown fires burn forest canopy fuels. They are usually generated by surface fires and represent a major change in fire behavior due to an increased rate of spread and heat released. Crown fires can be passive, active or conditional based on the capacity of the surface fire to move into areal fuels, and to the capacity of the burning canopy to move between individual trees.

Crown fire initiation occurs when the surface fire provides enough heat to raise the temperature of the canopy fuel to ignition temperature. In Van Wagner (1977) model, this minimum intensity is given by:

$$I_{ini}= (0.01 *CBH (460 + 25.9 FMC))^{1.5}$$

Where CBH is the canopy base height (m) and FMC is the foliage moisture content of the canopy cover. Foliar moisture content (FMC) is usually not known, but it is assumed that for most species old foliage should be around 100 percent and this value has been used as a default value when no other information is available (Scott 2001). This approach however does not consider any known humidity conditions of the site and in WFA the FMC is computed based on the 100h moisture content as follows:

$$FMC = 75 + 2\cdot m100h$$

Once the fire has transitioned to the canopy it is necessary to have a critical mass-flow rate for the fire to be self-sustained. Vang Wagner found this critical mass to be 0.05 kg m-2 sec-1 (Scott 2001) which can be used to determine a minimum crown fire rate of spread only dependent on the Canopy Bulk Density (CBD) and given by

$$R_{active} = 3 / CBD$$

Other existing models not used in WFA are Alexander (1998) which is very similar to Van Wagner (1977) but includes additional inputs like flaming residence time, plume angle and fuel bed characteristics, Cruz et at. (1999) fire transition model, and Cruz et al. (2002) crown fire spread model given by:

$$ROS = c1\ U^{c2}\ CBD\cdot C3\cdot e^{c4xEFM}$$

Where U is the wind at 10m, CBD the canopy bulk density, EFM is the fine dead moisture content, and C1, C2, C3, C4 are a set of regression coefficients.

The model for the ROS of crown fires was computed by Rothermel (1991) through a linear regression between observed crown ROS and the surface fire model. It states that the crown fire of an active ROS is 3.34 times the rate of spread of the surface model 10 assuming a 0.4 wind reduction factor.

$$R = 3.34(R_{10})_{40\%}$$

Based on these conditions, crown fire may be classified as:

- Surface fire if neither the intensity nor the minimum crown ROS is met
- Passive Crown fire (torching): Fire spreads through the surface fuels, occasionally torching overstory trees. Overall ROS is that of the surface fire.
- Conditional Crown: Fire cannot transition to crown, but active crown fire is possible if there was a fire transition to crown by other means
- Active Crown: Fire spreads through the overstory tree canopy if both conditions are meet

Fire Type		Active crown fire?	
		No	Yes
Transition to crown fire?	No	Surface	Conditional Crown
	Yes	Torching	Crowning

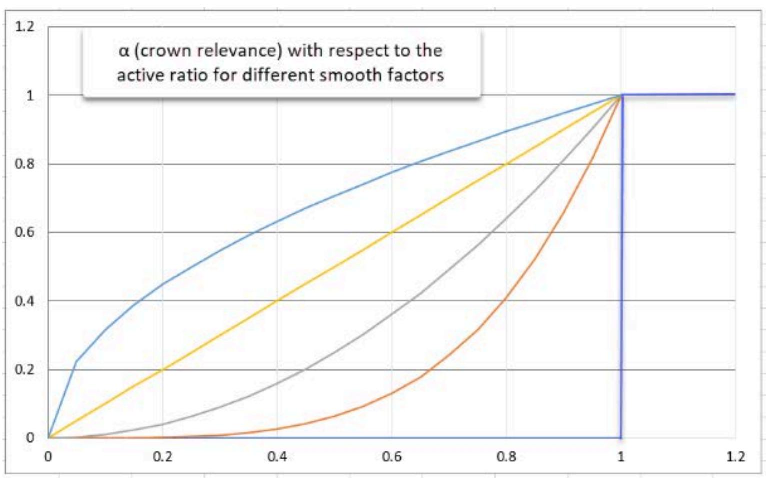
Crown fire classification as shown in BehavePlus

Van Wagner's crown fire transition and propagation models are well known and used operationally but have shown to have a significant underprediction bias when used in assessing potential crown fire behavior in conifer forests of western North America (Cruz et al. 2010). To try to correct this bias Technosylva has introduced two new parameters in the model that have been adjusted based on the analysis carried out by the scientific team using data from the last two fire seasons in California. The model introduces two new parameters 1) a crown factor multiplier for the Canopy Bulk Density (CBD) which decreases the minimum crown ROS required to have an active crown fire, and a factor that forces a smooth transition between the surface and the crown fire behavior. The final ROS of the overall fire when crown fire type is conditional or crowning is a weighted average of surface and crown ROS

$$ROS = surfROS * (1-\alpha) + \alpha * crownRos$$

Where the value α ranges from 0 to 1 and depends on the **active ratio** in the following way:

$$\alpha = activeRatio^{1/smoothFactor}$$



Example effect of the smooth factor (0 blue, 0.25 red, 0.5 gray, 1 yellow) in the crown contribution for active ratios lower than 1

At present, with WFA the crown CBD factor is set to 1.2 and the smooth factor to 0.4. This approach to provide a gradual transition in the fire's rate of spread (and flame length) from the initial onset of crowning similar to the crown fraction burned (CFB) (Alexander 1998) used in other modeling systems like FlamMap, FARSITE or Nexus, with the main difference being the smoothing function itself. Cruz et al. observes that there is no evidence of such a smooth transition between surface and crown fire regimes in the experimental data but rather an abrupt transition is observed far more commonly. In our context, however, where the main aim is to produce a forecast risk and not to simulate an individual fire we consider that it is important to reflect the fact that the fire conditions are close to generate an active crown fire.

For a more in-depth discussion of the crown fire models please read Cruz et al (2010) Scott et al. (2006)

Wind adjustment factor

Fire simulations require wind speed at midflame to compute surface fire spread and at 20ft to compute crown fire characteristics. To convert the wind between the two heights, WFA uses the wind adjustment factor (WAF) found in Andrews (2012) and implemented in the software BehavePlus and Farsite. The model is based on the work of Albini and Baughman (1979) and Baughman and Albini (1980), using some assumptions made by Finney (1998). This implementation considers two different models for sheltered and unsheltered conditions from the overstory. As described in Andrews (2012), the unsheltered WAF is based on an average wind speed from the top of the fuel bed to a height of twice the fuel bed depth. The sheltered WAF is based on the assumption 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. The unsheltered WAF model is used if crown fill portion is less than 5 percent. Midflame wind speed is the 20-ft wind multiplied by the WAF.

Unsheltered WAF depends on the surface fuel bed depth (in feet):

$$WAF = \frac{1.83}{\ln ln\left(\frac{20+0.36H}{013H}\right)}$$

Sheltered WAF:

$$WAF = \frac{0.555}{\sqrt{fH}*\ln ln\left(\frac{20+0.36H}{0.13H}\right)}$$

With H, the canopy height, and f ,the crown fill portion, depending on the canopy cover (CC) and the crown ratio (CR):

$$f = CC*CR / 3$$

$$CR = (CH-CBH) / CH$$

CR is the ratio of the crown length to the total height of a tree.

Time evolution

The fire models can predict the potential ROS of the front at any point and direction but are not able to compute the evolution of the fire perimeter in time. The main models to do that are:

1) Using Huygens principle of wave propagation like in Farsite (xxx) and discretizing in time
2) Using a Minimum Travel Time Algorithm or Fast Marching method, and discretizing in space
3) Using the more general but usually slower Level Set Method.

In the context of wildfires, Huygens principle states that each point on a fire front is in itself the source of an elliptical wavelet (fire) which spreads out in an independent way in the forward direction. This approach is numerically solved by splitting the perimeter into a set of nodes, computing the evolution of those nodes in the direction normal to the perimeter based on the ROS given by the propagation model and a given time steps, and then reconstructing the front based on the position of the transported nodes. The main weakness of vector-based approaches is the need for a computationally costly algorithm for generating the convex hull fire-spread perimeter at each time step, especially in the presence of fire crossovers and unburned islands (Ghisu et al. 2014). Raster based implementations are computationally more efficient (Glasa et al. 2008), but can suffer from significant distortion of the produced fire shape if the number of neighboring cells considered (number of possible spread directions) is low.

Spotting

Wildfires can create powerful updrafts which launch burning firebrands into the atmosphere, these firebrands are then carried horizontally by the wind landing some distance downwind from the source and creating a new ignition. Due to its unpredictable nature, fire-spotting modeling, here, is considered through a statistical approach.

Encroachment

Encroachment is a critical component in the WFA fire modeling simulations as it affects the number of buildings, assets, facilities and population impacted. It does not have a relevant effect on other impact metrics. To take advantage of enhanced algorithms for spread encroachment using adjacent fuels and fire behavior data, the non-burnable (and especially urban) fuel classification needed to be updated to provide better granularity and characterization of the type of urban/WUI. Accordingly, to test these methods an enrichment of the current fuels data was developed by Technosylva to delineate urban fuels into different types of urban and also a level of density of buildings. This enhancement of the basic Scott and Burgan fuel models is used in combination with enhanced encroachment algorithms to more accurately calculate potential impacts to buildings and population.

Urban areas have been classified into classes depending on their structure (roads, urban core, isolated, sparse) and their surrounding fuels, characterized as high versus low fire behavior fuels). Specific encroachment factors can then be applied to each grouping.

Spark Modeling

Electrical failures can cause sparks and produce an ignition meters away from the asset location. To take this into account, the WFA allows the ignition point location to be displaced if the underlying vegetation type is either non-combustible or WUI. This displacement is in the direction of the wind and is proportional to the wind speed. The displacement distance and wind speed algorithm has been developed using expert opinion from electric utility engineers familiar with asset failure and ignition probability.

Weather

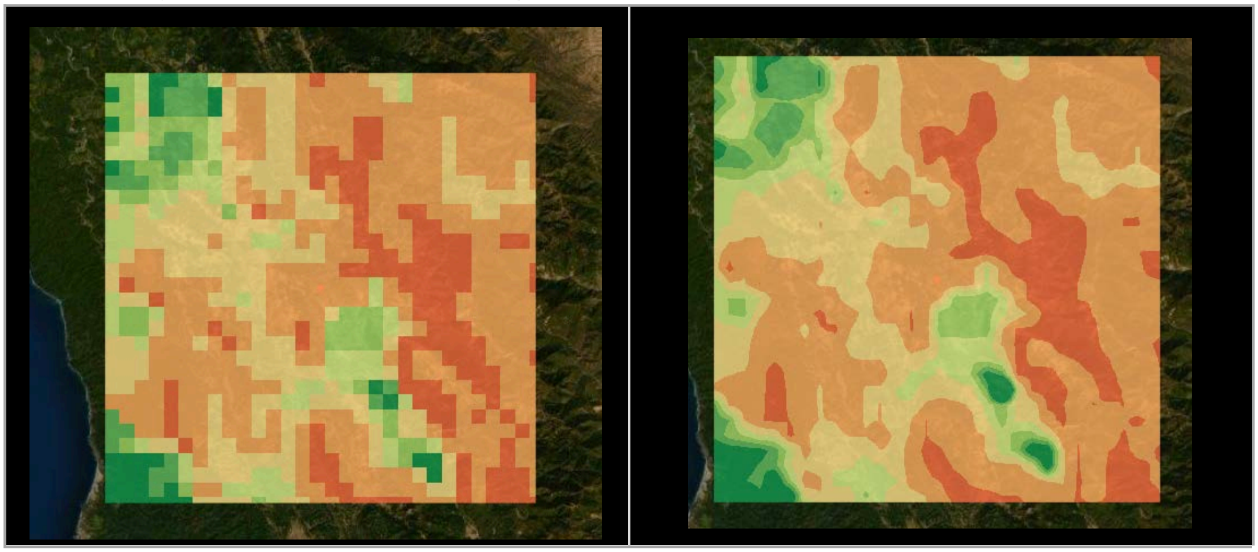
WFA requires historical daily weather data to run the fire simulations. The minimum required variables are the wind speed at 10m, the dead moisture content, and the live moisture content. More explicitly:

- Northward 10m wind speed
- Eastward 10m wind speed
- Dead moisture content 1hr
- Dead moisture content 10hr
- Dead moisture content 100hr
- Herbaceous moisture content

- Woody moisture content

The dead moisture may be given by the client or may be computed based on the Nelson model. Similarly, the herbaceous moisture content may be provided by the client or may be computed using Technosylva's Machine Learning algorithm based on historical NDVI weather reading. The Technosylva DFM model has been developed to meet customer needs using the latest modeling approaches. The input wind speed required by the propagation model is 20ft; to convert the initial 10m wind speeds to 20ft, we use a logarithmic profile from Andrews (2012) leading to a 13% wind speed reduction.

Weather data is obtained from the Weather Research and Forecasting (WRF) Model weather forecast data. The forecast weather has a 2 km resolution which can lead to sharp changes in weather conditions between neighboring cells. In order to increase accuracy and meet the underlying 30m cell size resolution of the fuels data, weather data is interpolated spatially using a bilinear interpolation scheme. The smoothing of the source weather data ensures that integration with the wildfire behavior models results in outputs that do not have hard edges in the data.



Left: Initial weather definition. Right interpolated weather definition

Impact and consequence value calculation

Wildfire spread modeling is undertaken with asset ignition locations to derive potential impacts. The output impact values (risk metrics) are assigned back to the asset ignition point location. Using this approach allows us to differentiate between the risk output associated with different assets (and their ignition locations) using the same weather data although weather values may vary based on spatial location and time of day (hourly). For both operational and mitigation applications, the wildfire spread modeling is conducted using High Performance Computers (HPC) and typically involves hundreds of millions of spread simulations. The amount of simulation will vary depending operational use with daily forecasts versus mitigation planning use with hundreds of weather scenarios.

The main goal for the WFA simulations is to create a forecast risk associated to each ignition point and surrounding area. This is done by running individual simulations and associating the following main risk metrics back to each ignition point. The following baseline risk metrics are calculated from the spread simulations

- Acres Burned (referred to as Fire Size Potential)
- Number of Buildings Threatened
- Estimated Number of Buildings destroyed
- Population impacted

Numerous conventional fire behavior outputs are also calculated, the most important being:

- Rate Of Spread (ROS)
- Flame Length (FL)
- Fire Behavior Index (FBI) – combination of ROS and FL

2.4.4 Limitations (see Guide ASTM E 1895)

Identified the limitations of the model based on the algorithms and numerical techniques.

The Technosylva WFA platform Is an integration of numerous speciality models designed to address specific scientific requirements and methods.

The following assumptions applied to the models used in WFA:

- The physical framework development is based on an idealized situation in steady state spread
- Rate Of Spread at a point only depends on the conditions at that point (point-functional models). This means that there is no increase in speed due to non-local contributions of the fire front.
- Fire model is not directly coupled with the atmosphere. Fire will not modify local atmosphere. However, this is being addressed with seamless integration with the WRF-SFIRE model in development at San Jose State University, Wildfire Interdisciplinary Research Center. WRF-SFIRE is an option available to WFA customers to address specific convection based fire scenarios.
- Fire is always assumed to be fully developed with fire acceleration, flashover, or decay not being considered.
- Atmospheric instability, which may have a deep impact on ROS (Beer 1991), is not considered in the model in any way.
- Gusts are not considered in the model
- No interaction between slope and wind other than creating an effective or equivalent wind. This means that fire is assumed to have an elliptical shape no matter the alignment of wind and slope.
- Experimental data is scarce and the empirical adjustment of models have been based on wind tunnel experiments and a few well documented fires
- Fuel array description of the vegetation may not perfectly describe fuel characteristics.
- Spotting is only considered in surface fires

2.5 Data Libraries

Provide background information on the source, contents, and use of data libraries.

This section provides a brief summary of the key input datasets required for wildfire behavior analysis and risk analysis. The following categories of input data are:

1. Landscape characteristics
2. Weather and atmospheric data

3. Fuel moisture
4. Values at risk (highly valued resources and assets)
5. Possible ignition sources
6. Fire activity

2.5.1 Landscape Characteristics

This includes a range of possible data that describe the characteristics of the landscape. The most important data are related to surface and canopy fuels, and vegetation. There are many publications available that describe these datasets, many from the USFS Missoula Fire Lab. Most use the Scott & Burgan 2005 Fuels Model Set standard for classification of fuels data.

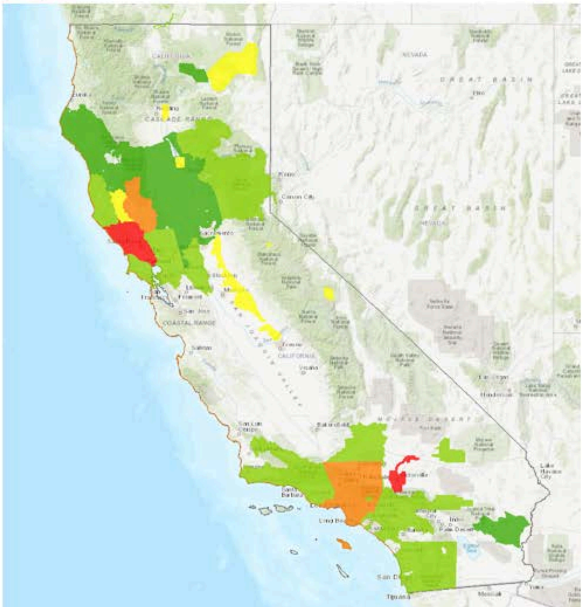
Standard fire behavior analysis input layers are:

1. Terrain – elevation, slope, aspect
2. Surface fuels (Scott & Burgan 2005)
3. Canopy fuels
    a. Canopy height
    b. Canopy base height
    c. Canopy bulk density
    d. Canopy closure
4. WUI and and Non Forest Land Use classes (Technosylva, 2020)

2.5.2 Surface and Canopy Fuels

For these layers, data developed by Technosylva is used. Technosylva provides an annual fuel updating subscription where initial fuels is developed using advanced remote sensing object segmentation methods using high resolution imagery, available LiDAR & GEDI, and other standard imagery sources, such as NAIP , Sentinel 2 and Landsat. This is supplemented with in-the-field surveys to verify the fuels for possible areas of concern and to validate the fuels classification. Surface and canopy fuels data is critical for accurate fire behavior modeling, so it is paramount that this data is up-to-date, and when used, results in the observed and expected fire behavior.

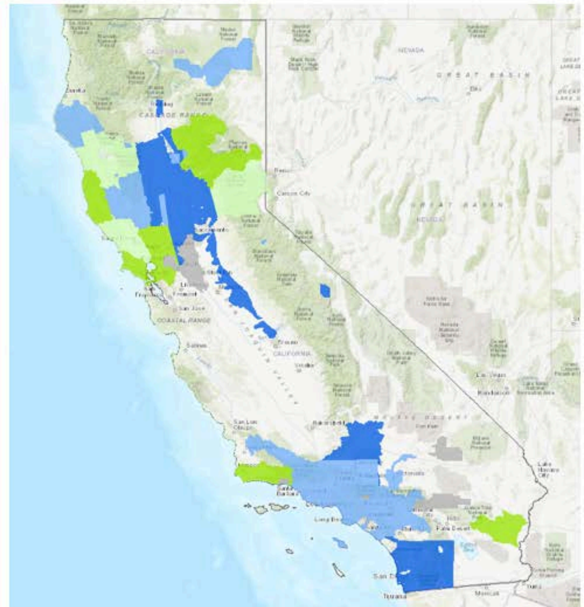
Survey Date



Survey Date
- 2019
- 2018
- 2017
- 2016
- 2013

Summary
- 2019 → 14,906,880 ac
- 2018 → 26,874,880 ac
- 2017 → 4,423,040 ac
- 2016 → 6,377,600 ac
- 2013 → 2,319,360 ac

Point Cloud Density



Point Cloud Density (point/m2)
- 0 - 5
- 5 - 10
- 10 - 15
- 15 - 30
- Unknown

LIDAR Data used for Technosylva Fuels 2021, with capture date and points density

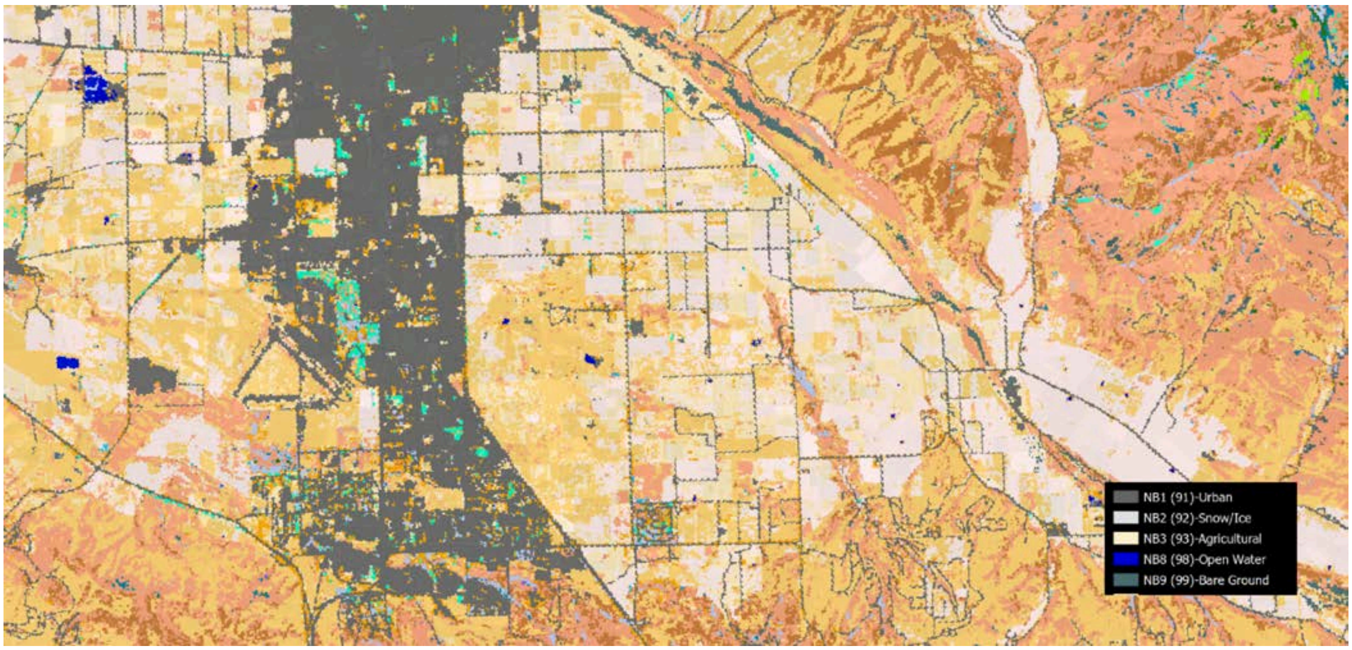
Surface and canopy fuels are updated throughout the year, to accommodate changes to the fuels, typically monthly during fire season. This ensures that all major disturbances, such as fires, urban growth, landslides, etc. are updated in the fuels data. A variety of methods, including burn severity analysis, are used to update the fuels. Up to date fuels data is critical to ensuring the fire behavior outputs from our modeling are accurate, as it is a key input into risk analysis.

Technosylva continually tests new fuels datasets that become available from other sources, such as LANDFIRE, federal risk assessment regional projects, and independent sources, such as the California Forest Observatory data. Unfortunately, the publicly available data does not perform at the level required when confronted with operational testing. In general, these publicly available data do not result in fire behavior outputs that facilitated accurate predictions. Ultimately with any fuels dataset, the quality and accuracy of the fuels is measured on whether it produces ‘observed and expected fire behavior’. Fortunately, Technosylva is able to test this data, and other fuels data including their custom data, operationally on a daily basis with CAL FIRE and the IOUs against active wildfires to see how it performs.

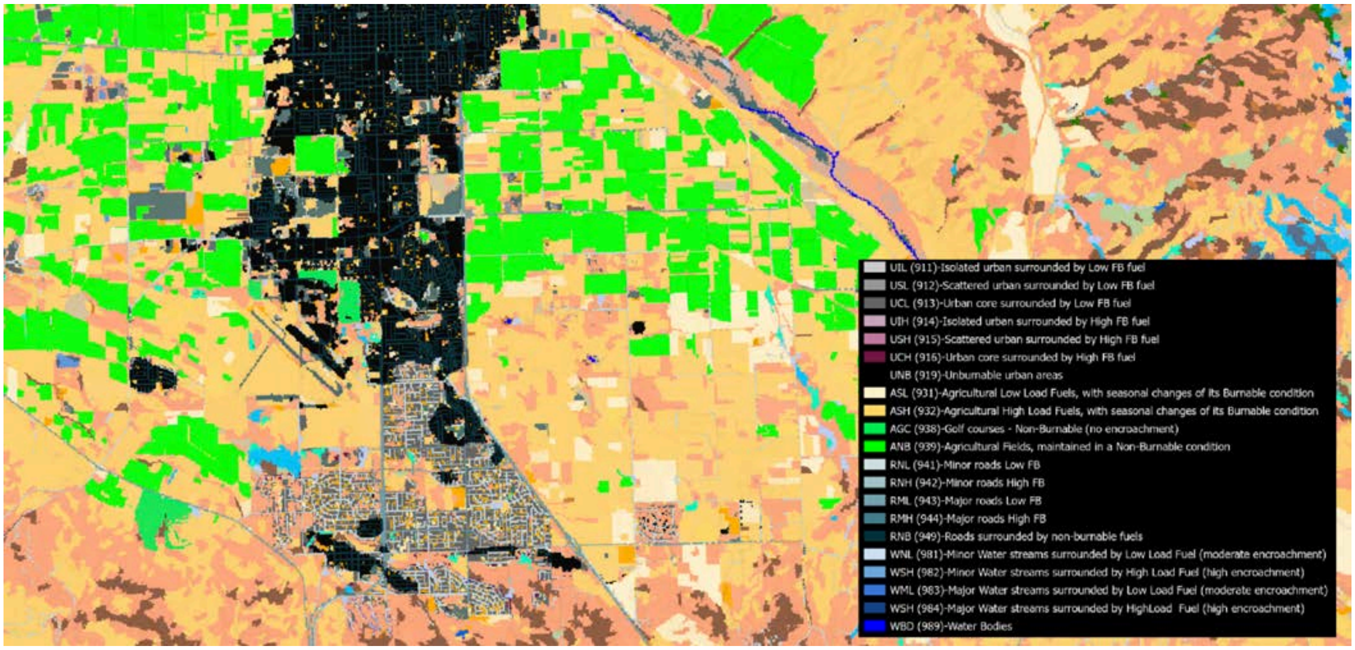
Updates to the fuels, and algorithms that use the fuels data for fire behavior modeling are on-going with us, as we continue to enhance the data and algorithms to match observed fire behavior across the state. These methods and algorithms are proprietary.

WUI and Non-Forest Fuels Land Use classes are based on a Technosylva proprietary method that characterizes WUI and other land uses classes that have been a typical limitation of the Scott and Burgan classification, as they are defined in general non burnable classes. In combination with the Surface Fuels, this provides a solid foundation for fire behavior and impact analysis.

The following two figures present an example of publicly available LANDFIRE data commonly used for fire modeling, and the custom Technosylva fuels used.



LandFire Fuels – Non Burnable Classes



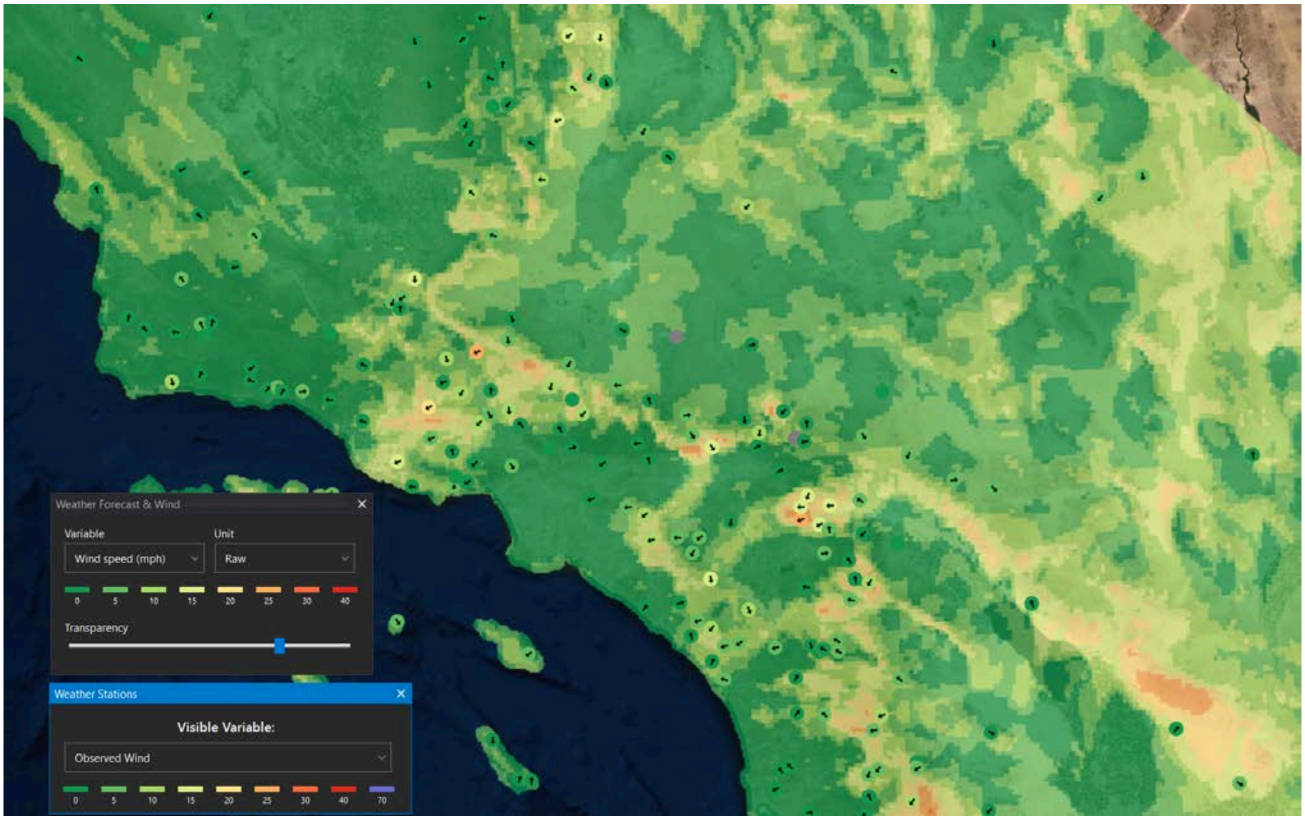
Technosylva Fuels Dec 2021 – WUI and Non-Forest Fuels Classes

2.5.3 Weather and Atmospheric Data

WRF data is developed using third party weather and predictive services experts available through commercial providers. Data is 2 km spatial resolution and hourly (temporal) for a multi-day period, up to five+ days. Multiple forecasts are generated daily.

Weather observation data can also be used along with, or independently, to support fire behavior analysis. This data is typically available through published weather stations on MesoWest, or through commercial providers, such as Synoptic. The methods of how this data can be integrated within the Technosylva software and processes is proprietary.

The following figure shows a typical 2km WRF model of wind speed overlaid with weather stations data (WFA software example).



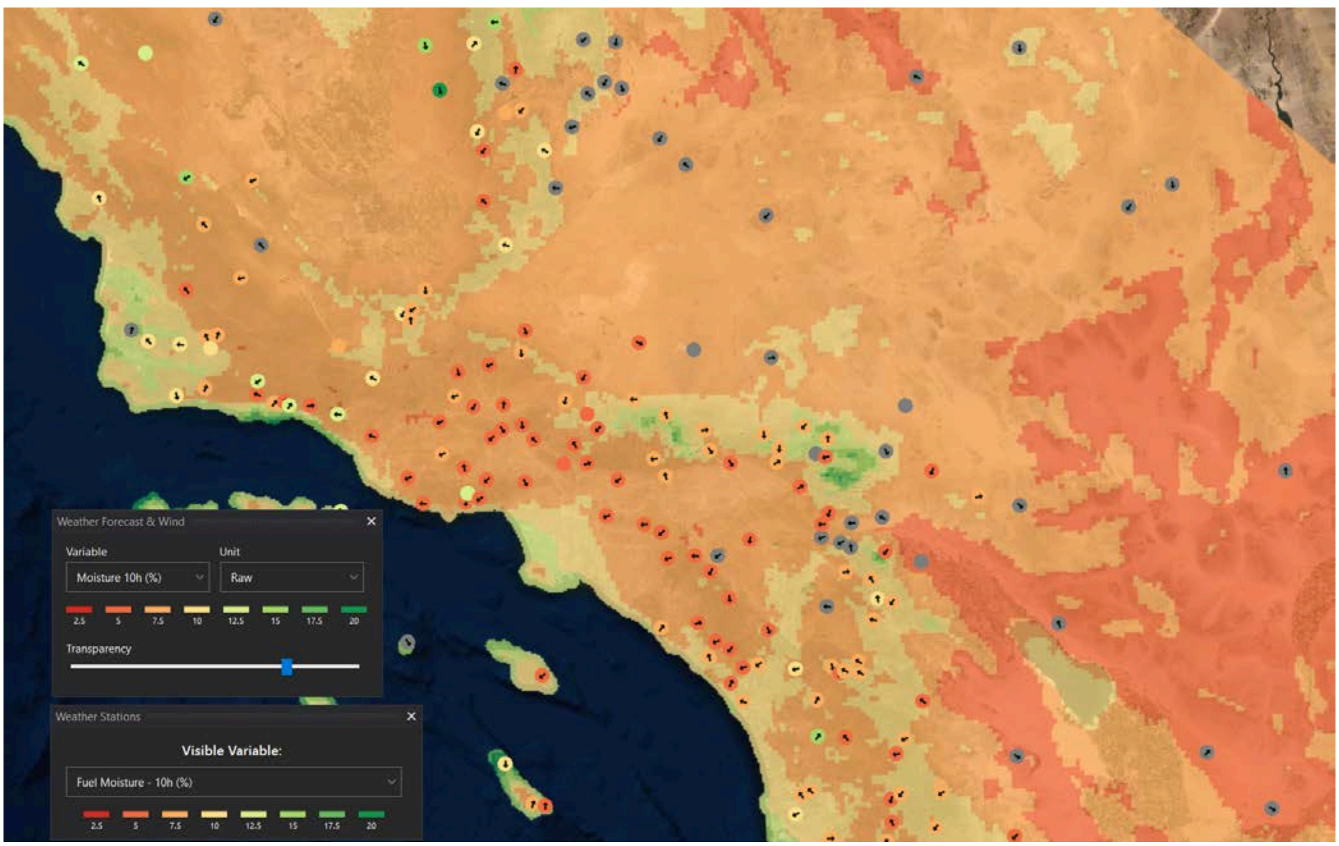
Predicted (WRF model) and Observed Wind (Weather Stations, Synoptic)

2.5.4 Fuel Moisture

Fuel moisture data is also a key input into fire behavior modeling. Fuel moisture can be characterized as either Dead or Live fuel moisture. Standard methods for measuring and quantifying fuel moistures are well documented in publications by the USFS Missoula Fire Lab and other research agencies.

However, to date the ability to accurately predict live and dead fuel moistures at high resolution has been limited. Only a few IOUs and commercial vendors are producing daily estimates that can be integrated into fire modeling. Technosylva produces both a dead and live fuel moisture data product that combines historical and current sample data with remotely sensing imagery in a machine learning model to estimate daily data products. These methods are proprietary although they are substantiated with several publications and on-going collaboration between the IOUs, Technosylva and fire weather and behavior research agencies. This fuel moisture data product is used by CAL FIRE and several IOUs across seven western US states.

The following figure shows the Technosylva Dead Fuel Moisture overlaid with weather stations data (WFA software example).



Predicted (WRF model) and Observed 10-hr Fuel Moisture (Weather Stations, Synoptic)

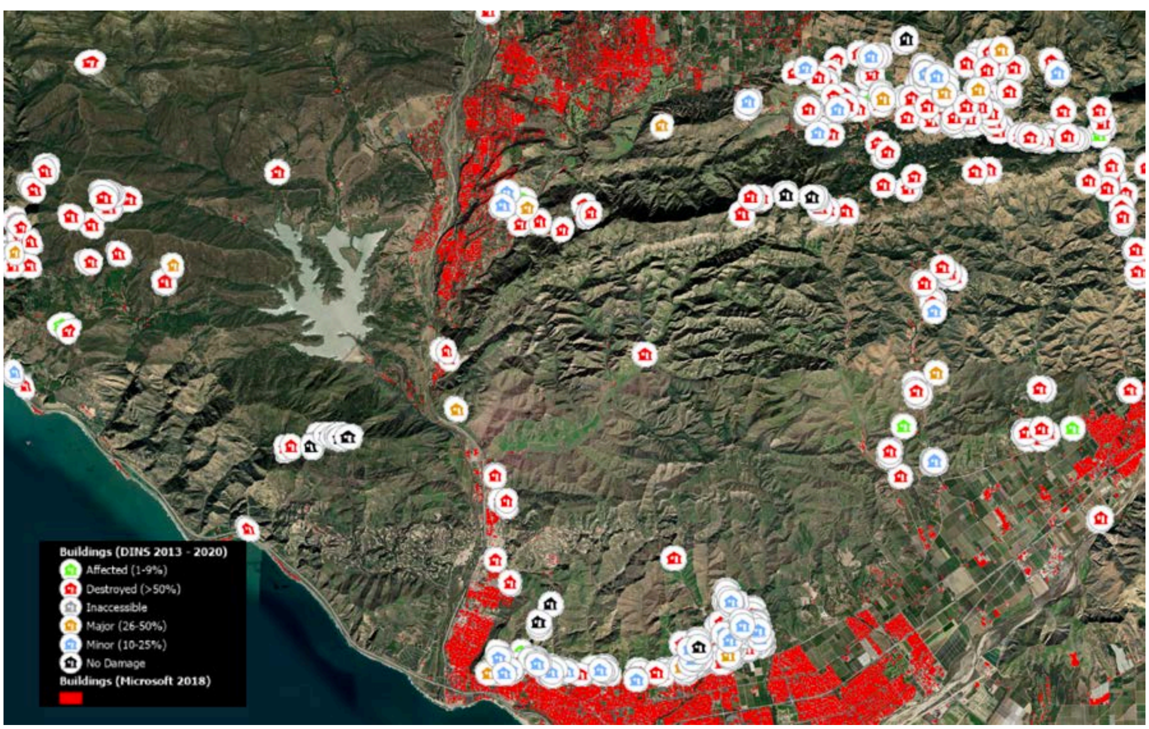
2.5.5 Values at Risk

Values-at-Risk data reflects the resources and assets that exist across that landscape that we are concerned about. Typically, 'resources' refers to natural items while 'assets' refers to man made items. Wildfire modeling is used to identify the "risk" associated with resources and assets, with risk representing the possibility of loss or harm occurring due to wildfire.

VAR data is typically characterized into public safety or financial impacts. Technosylva IOU customers use similar input datasets for VAR, such as population count (location), building footprints, and critical facilities. A variety of datasets exist to define the location and characteristics of these VAR, each with varying temporal and spatial accuracy. Census data is a common source for population data along with ORNL LandScan data (population count). LandScan has become a de facto standard for static wildfire risk assessments across the Nation in the past 10 years. It is available through the Dept. of Homeland Security HSIP program for certified vendors of government agencies, or the agencies themselves. It is typically updated every 2 years with a 90 meter spatial resolution of population count. Technosylva currently uses the latest 2021 LandScan data for calculating population impacts.

The Microsoft Buildings Footprint dataset is a publicly available free data source used as a starting point by many vendors and agencies. Technosylva has taken this data and updated it using local high resolution imagery data sources to enhance the data. The original Microsoft data is a good starting point, however it does have holes with missing data and some misrepresentation of buildings with natural features. This data was updated in 2020 by Microsoft. This provides the primary source for the buildings data used by Technosylva.

Population and buildings are the two primary datasets used as input into wildfire risk analysis, although most IOU customers add confidential data to derive more detailed consequence metrics. These are proprietary to the IOUs and cannot be shared by Technosylva.



Buildings (Microsoft 2020) and Damaged Inspections data (DINS) from CAL FIRE

2.5.6 Possible Ignition Sources

Wildfire ignition data varies greatly depending on the organization and purpose of the wildfire risk analysis. Traditionally, agency driven risk assessments will use historical fire location data to create Historical Fire Occurrence datasets, reflecting ignition density over a specific time period. This data is obtained from federal and state fire reporting systems.

IOUs are often concerned with using their assets as possible ignition sources, in equipment failure scenarios or extreme weather events, where a spark from an electric utility asset may cause a fire ignition. Risk can be assessed related to the probability of ignition for electric utility assets, or more commonly with the potential spread and impacts of a wildfire ignited by an asset. Technosylva provides integration of both ignition and spread analysis to derive risk metrics using VAR data. This focuses on assigning possible consequence back to the electric utility assets to identify those assets more prone to having significant impacts should a wildfire ignite. Different proprietary methods exist to integrate and model probability of ignition data for electric utility assets with consequence modeling. Referred to as “asset wildfire risk” this information can be used to support operational decisions, such as PSPS, resource allocation and placement, and stakeholder communication, in addition to short and long term mitigation planning efforts, reflected in IOU WMPs. The weather and fuels inputs will vary depending on the purpose of these risk analyses.

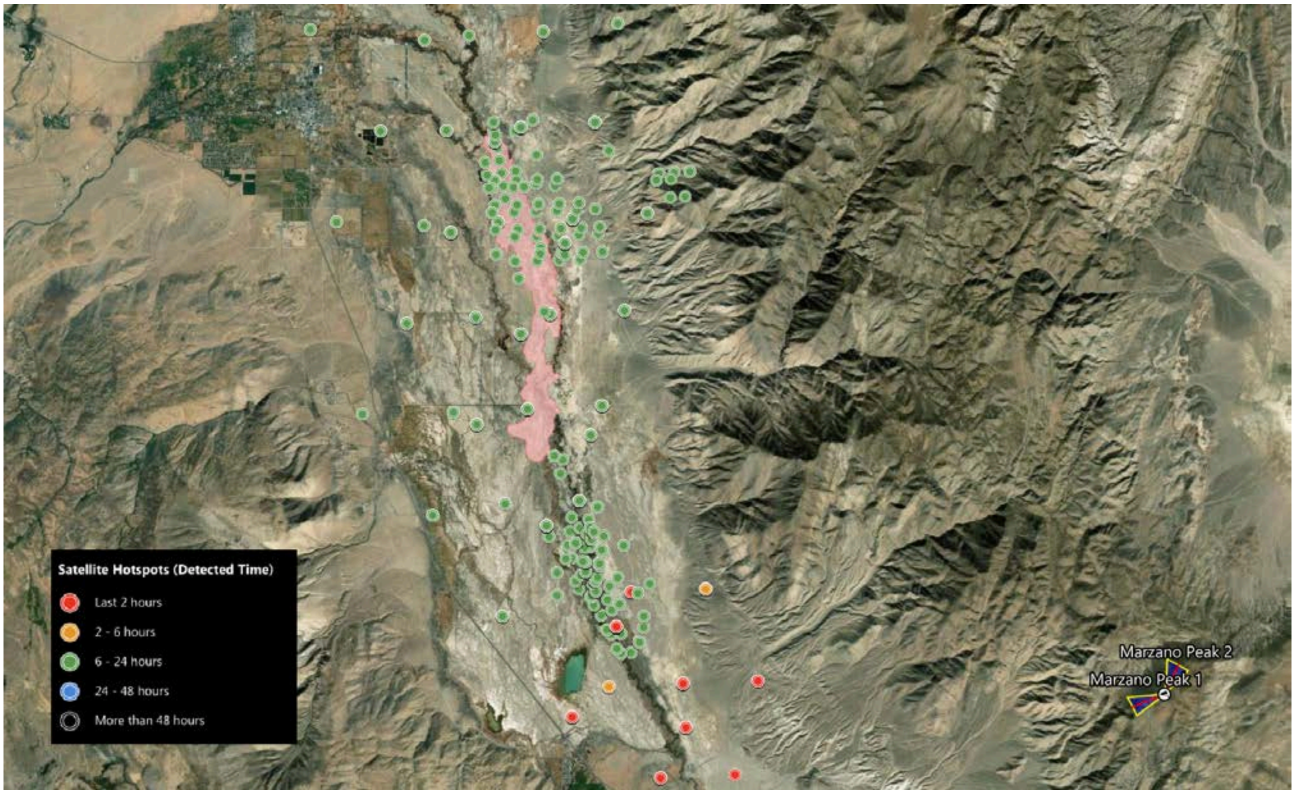
IOUs and agencies are also concerned with non-asset wildfire ignitions and the risk associated with these ignitions due to possible spread and potential impacts. Technosylva has developed proprietary methods for deriving territory wide risk that integrates millions of possible ignition points with wildfire spread modeling to derive standard risk outputs, similar to “asset risk” metrics. These output metrics vary greatly depending on the customer and purpose for using the risk data. The methods and outputs are proprietary.

2.5.7 Fire Activity

The fire activity data used to support operational situational awareness is captured from different sources:

- VIIRS and MODIS Satellite hotspots, from public sources (FIRMS)
- GOES 16 and 17 data based on agreement with providers to the IOUs
- Lighting data also from IOU’s providers
- Fire Perimeters from Open Wildfire data from NIFC
- Fire activity from National Guard data from Fire Guard program
- Alert Wildfire Cameras integration

The following figure shows an example of Fire Activity data integrated into the Technosylva WFA system. All data is temporal and displayed color coded based on a selected time from the software timeline.



Hotspots, Fire Perimeters and Alert Wildfire Cameras

2.5.8 Summary of Input Data Sources

The following table presents a summary of the data sources used in the wildfire risk analysis. Some data varies slightly depending on mitigation versus operational use.

DATASET	SPATIAL RESOLUTION (meters)	TEMPORAL RESOLUTION	DATA VINTAGE	SOURCE
Landscape Characteristics				
TERRAIN	10	YEARLY		USGS
SURFACE FUELS	30/10	PRE FIRE SEASON, MONTHLY UPDATE IN FIRE SEASON, END OF FIRE SEASON	2020	TECHNOSYLVA
WUI AND NON FOREST FUELS LAND USE	30/10	TWICE A YEAR	2020	TECHNOSYLVA
CANOPY FUELS (CBD,CH,CC,CBH)	30/10	PRE FIRE SEASON, MONTHLY UPDATE IN FIRE SEASON,	2020	TECHNOSYLVA

DATASET	SPATIAL RESOLUTION (meters)	TEMPORAL RESOLUTION	DATA VINTAGE	SOURCE
		END OF FIRE SEASON		
ROADS NETWORK	30	YEARLY		USGS
HYDROGRAPHY	30	YEARLY		USGS
CROPLANDS	30	YEARLY	1997	USDA
Weather and Atmospheric Data				
WIND SPEED	2000	HOURLY / 124 HOUR FORECAST	1990	ADS/DTN
WIND DIRECTION	2000	HOURLY / 124 HOUR FORECAST	1990	ADS/DTN
WIND GUST	2000	HOURLY / 124 HOUR FORECAST	1990	ADS/DTN
AIR TEMPERATURE	2000	HOURLY / 124 HOUR FORECAST	1990	ADS/DTN
SURFACE PRESSURE	2000	HOURLY / 124 HOUR FORECAST	1990	ADS/DTN
RELATIVE HUMIDITY	2000	HOURLY / 124 HOUR FORECAST	1990	TECHNOSYLVA
PRECIPITATION	2000	HOURLY / 124 HOUR FORECAST	1990	ADS/DTN
RADIATION	2000	HOURLY / 124 HOUR FORECAST	1990	ADS/DTN
WATER VAPOR MIXING RATIO 2m	2000	HOURLY / 124 HOUR FORECAST	1990	ADS/DTN
SNOW ACCUMULATED - OBS	1000	DAILY	2008	NOAA
PRECIPITATION ACCUMULATED - OBS	4000	DAILY	2008	NOAA
BURN SCARS	10	5 DAYS	2000	NASA/ESA
WEATHER OBSERVATIONS DATA	Points	10 MIN	1990	SYNOPTIC
Fuel Moisture				
HERBACEOUS LIVE FUEL MOISTURE	250	DAILY / 5-DAY FORECAST	2000	TECHNOSYLVA

DATASET	SPATIAL RESOLUTION (meters)	TEMPORAL RESOLUTION	DATA VINTAGE	SOURCE
WOODY LIVE FUEL MOISTURE	250	DAILY / 5-DAY FORECAST	2000	TECHNOSYLVA / ADS
1 hr DEAD FM	2000	HOURLY / 124 HOUR FORECAST	1990	TECHNOSYLVA / ADS
10 hr DEAD FM	2000	HOURLY / 124 HOUR FORECAST	1990	TECHNOSYLVA / ADS
100 hr DEAD FM	2000	HOURLY / 124 HOUR FORECAST	1990	TECHNOSYLVA / ADS

DATASET	SPATIAL RESOLUTION (meters)	TEMPORAL RESOLUTION	DATA VINTAGE	SOURCE
Values at Risk				
BUILDINGS	Polygon footprints	YEARLY	2020-21	MICROSOFT/TECHNOSYLVA
DINS	Points	YEARLY	2014-21	CAL FIRE
POPULATION	90	YEARLY	2019	LANDSCAN,ORNL
ROADS	Vector lines	YEARLY	2021	CALTRANS
SOCIAL VULNERABILITY	Plexels	YEARLY	2021	ESRI GEOENRICHMENT SERVICE
FIRE STATIONS	Points	YEARLY	2021	ESRI, USGS
BUILDING LOSS FACTOR	Building footprints	YEARLY	2022	TECHNOSYLVA
CRITICAL FACILITIES	Points	YEARLY	2021	FRAP – CAL FIRE
Potential Ignitions locations				
IOU DISTRIBUTION & TRANSMISSION LINES	Linear segments	Updated quarterly	2022	IOUs
IOU POLES & EQUIPMENT	Points	Updated quarterly	2022	IOUs
Fire Activity				
HOTSPOTS MODIS	1000	TWICE A DAY	2000	NASA
HOTSPOTS VIIRS	375	TWICE A DAY	2014	NASA
HOTSPOTS GOES 16/17	3000	10 MIN	2019	NASA
FIREGUARD	Polygons	15 MIN	2020	NATIONAL GUARD
FIRE SEASON PERIMETERS	Polygons	DAILY	2021	NIFS
HISTORIC FIRE PERIMETERS	Polygons	YEARLY	1900	CAL FIRE
ALERT WILDFIRE CAMERAS	Live Feeds	1 min	Real Time	AWF Consortium
LIGHTING STRIKES	1000	1 MIN	Real Time	EARTH NETWORKS / OTHERS

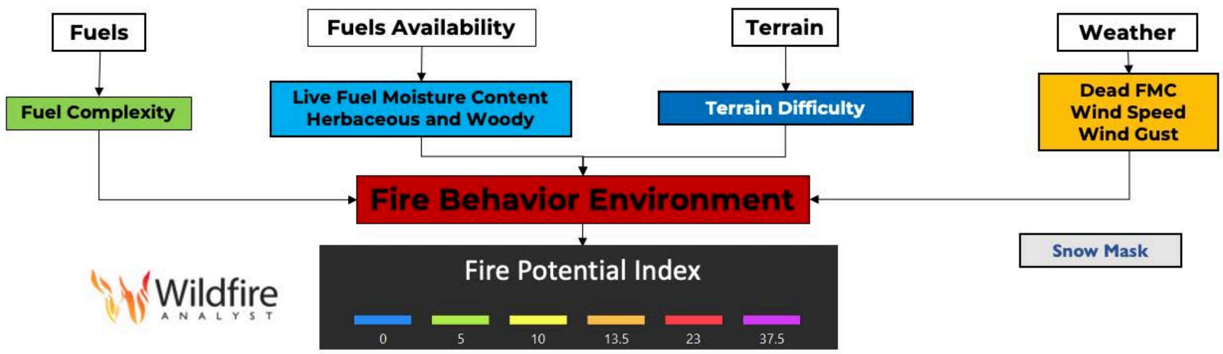
2.5.9 Fire Potential Index (FPI)

FPI quantifies the fire activity potential over the territory aiming to assist operational decision-making to reduce fire threats and risks. FPI allows agencies to easily analyze the short-term fire danger that could exist across the service territory and better communicate the wildfire potential on any given day and time, promoting safe and reliable operations.

Hexel-based (h3) FPI is a forecast product, which is produced on a daily basis, calculated every 3 hours at different h3 resolutions from level 4 to 8 (182 ac and 1km resolution approximately). One of the main advantages of this index is that it was calibrated with real fires (2012 to 2022) using VIIRS hotspots as a proxy of fire activity.

FPI estimates the expected daily number of VIIRS hotspots in a h3-hexel level 6.

FPI comprises several variables including fuels, terrain and weather:



Technosylva has integrated FPI into its operational decision-making WFA enterprise to facilitate its use operationally.

FPI promotes proactive and reactive operational measures through standard operating procedures aiming to reduce the likelihood facilities and assets will be the source of ignition for a fire when FPI is high or extreme.

FPI can be used to inform operation decisions (restrictions on the type of work being performed), as an input to PSPS decision-making and to make risk informed mitigation decisions.

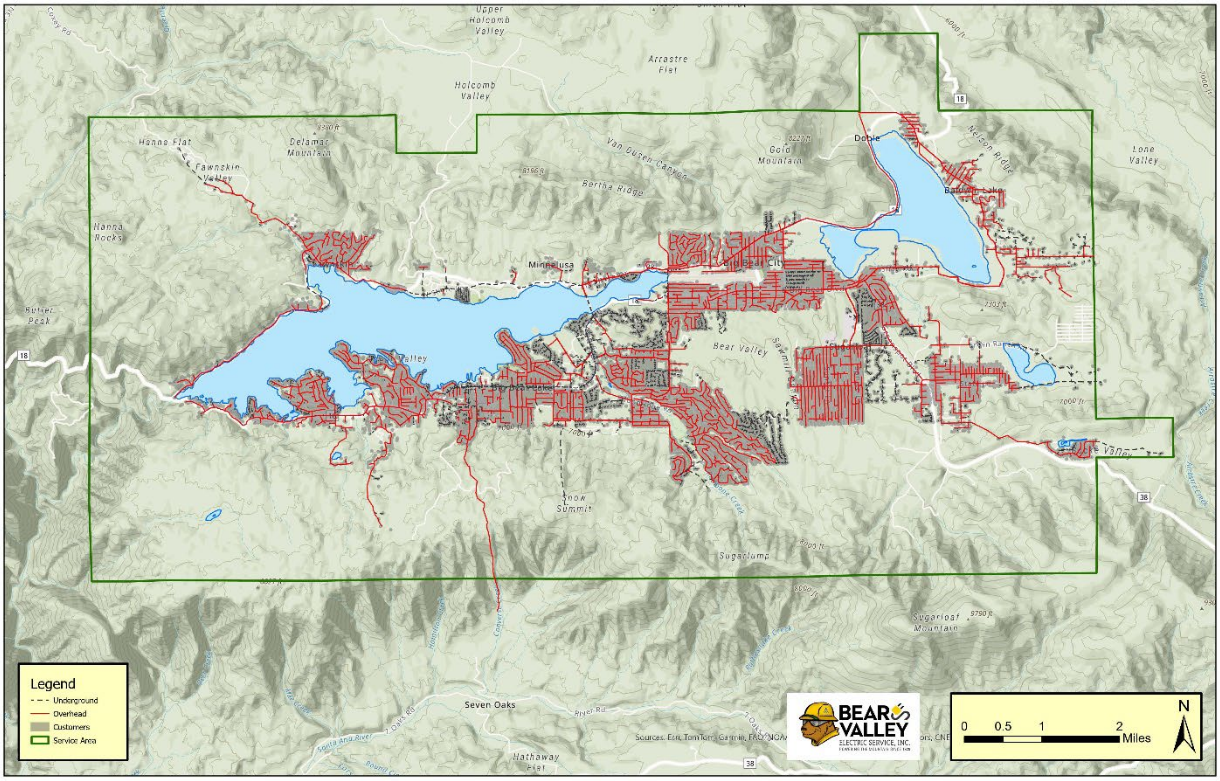
Fire Potential Index products developed for electrical utilities usually include weather data: wind speed, wind gusts, and both dead and live fuel moisture content. Technosylva's FPI also includes the Fuel Complexity (fuel structure, load and age) and Terrain Difficulty. These are key inputs of the classical fire triangle that explain fire behavior.

Technosylva's Fire Potential Index (FPI) has been empirically trained and validated with real fire activity. The product is hexel-based (h3) allowing a better temporal and spatial analysis of outcomes, including the analysis by district or any administrative division.

Appendix C. **Additional Maps**

Section 4.1 Service Territory

BVES Service Territory



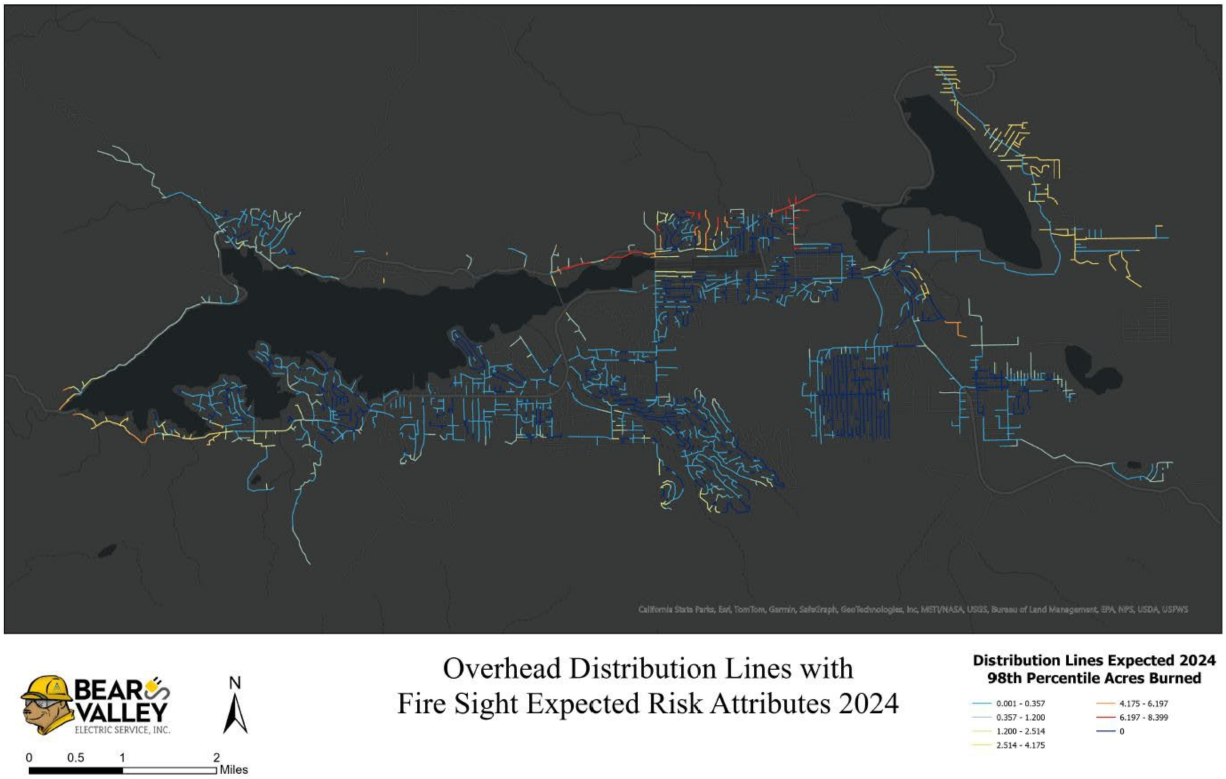
Section 4.3 Frequently De-energized Circuits

None of BVES circuits are frequently de-energized and BVES has not had a PSPS event.

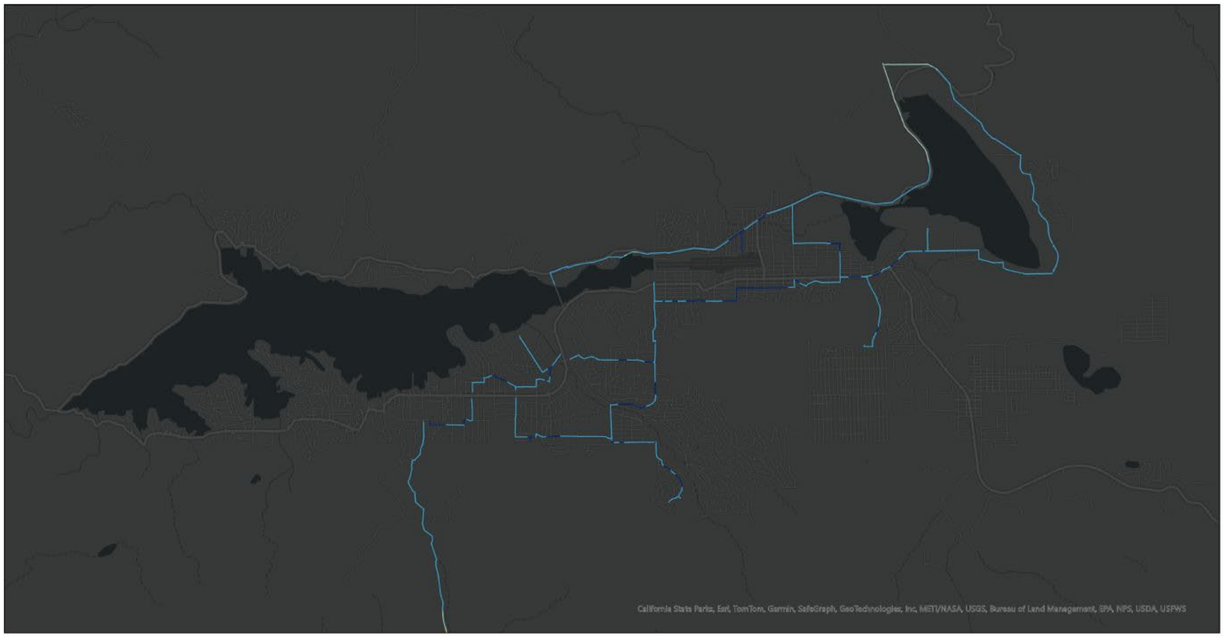
Section 5.5.1.1 Geospatial Maps of Top Risk Areas within the HFRA

The following maps are outputs from Technosylva Fire Sight and BVES Areas at Risk of PSPS

Overhead Distribution Lines Risk Attributes



Overhead Sub-Transmission Lines Risk Attributes



BEAR VALLEY ELECTRIC SERVICE, INC.

N

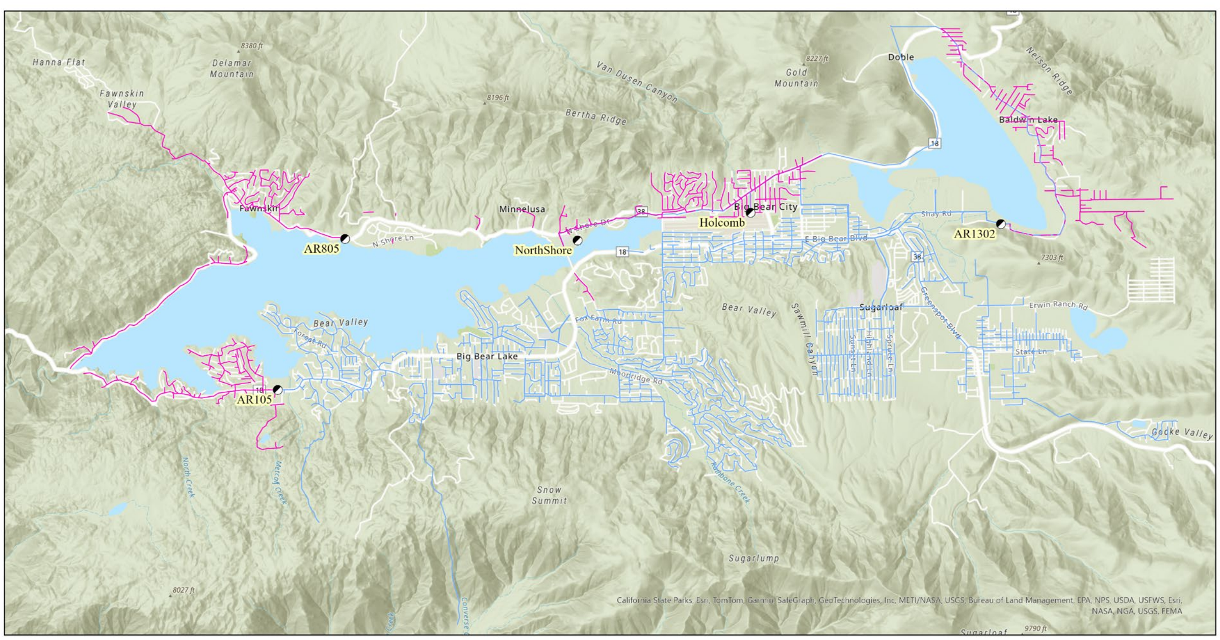
0 0.5 1 2 Miles

Overhead Distribution Lines with
Fire Sight Expected Risk Attributes 2024

Transmission Lines Expected 2024 98th Percentile Acres Burned

- 0.001 - 0.357
- 0.357 - 1.200
- 1.200 - 2.514
- 2.514 - 4.175
- 4.175 - 6.197
- 6.197 - 8.399
- 0

BVES Area at Risk of PSPS



BEAR VALLEY ELECTRIC SERVICE, INC.

N

0 0.5 1 2 Miles

BVES Areas at Risk of PSPS

Legend

- Higher PSPS Risk
- Lower PSPS Risk
- Recloser

Appendix D. **Areas for Continued Improvement**

Code and Title: BVES-23-01. Target Verification Methods

Description: BVES lists "quantitative" for its targets' verification method. It is not clear from this word how BVES will provide to verify progress toward and achievement of the target.

Required Progress: In its 2026-2028 Base WMP, BVES must include all methods used to verify progress of year-to-year targets within the table. BVES must clearly articulate its verification methods that are effective for supporting progress on and achievement of each target.

[2023-2025 WMP Discussed in Section 8.1, "Grid Design, Operations, and Maintenance"; Section 8.2, "Vegetation Management and Inspections"; Section 8.3, "Situational Awareness and Forecasting"; Section 8.5, "Community Outreach and Engagement."]
Section and Page Number of Any Improvements: BVES included quantitative targets in the following sections:

- Section 8.1. Targets (Grid Design, Operations, and Maintenance) Table 8-1. Grid Design, Operation, and Maintenance Targets by Year. (p. 111)
- Section 9.1. Targets (Vegetation Management and Inspections) Table 9-1. Vegetation Management Targets by Year (Non-inspection Targets) and Table 9-2. Vegetation Inspections and Pole Clearing Targets by Year. (p. 180)
- Section 10.1. Targets (Situational Awareness and Forecasting) Table 10-1. Situational Awareness Targets by Year. (p. 228)
- Section 11.1. Targets (Emergency Preparedness, Collaboration, and Community Outreach) Table 11-1 Emergency Preparedness and Community Outreach Targets by Year. (p. 251)
- Section 12.1. Targets (Enterprise Systems) Table 12-1. Enterprise Systems Targets. (p. 291)

BVES Response: For each target (quantitative or qualitative), Bear Valley has articulated its verification methods that are effective for supporting progress on and achievement of each target. They are listed in the table below:

Utility Initiative Name	Tracking ID	Target	Type	Verification
Emergency preparedness and recovery plan	EP_1	Review and Update as needed PSPS and EDRP each year	Qualitative	Management verifies plans are reviewed and updated as applicable.
External collaboration and coordination	EP_2	Conduct Stakeholder Briefs quarterly and Annual Tabletop Exercise	Qualitative	Management attends briefs and reviews exercise records

Public communication, outreach, and education	EP_3	Achieve satisfactory outreach evaluation on semi-annual PSPS and wildfire customer survey. (Satisfactory is >60% overall.)	Qualitative	Management reviews survey results after each survey
Customer support in wildfire and PSPS emergencies	EP_4	Review procedures for Customer support in wildfire and PSPS emergencies annually	Qualitative	Management verifies plans are reviewed and updated as applicable.
Asset management and inspection enterprise system(s)	ENT_1	Conduct Annual Usefulness and Impact of Enterprise System Survey and Take Corrective Action on Results	Qualitative	Management reviews survey results
Vegetation management enterprise system	ENT_2	Conduct Annual Usefulness and Impact of Enterprise System Survey and Take Corrective Action on Results	Qualitative	Management reviews survey results
Covered Conductor Replacement Project (Reconductor)	GD_1	Circuit Miles	Quantitative	100% Field inspection by BVES staff and work order review by engineering
Fuse TripSaver Automation	GD_10	# of TripSavers connected to SCADA	Quantitative	100% Field inspection by BVES staff and work order review by engineering
Non-Exempt Surge Arrester Replacement	GD_11	# of Non-exempt surge arresters replaced	Quantitative	100% Field inspection by BVES staff and work order review by engineering
Tree Attachment Removal Project	GD_12	# of Tree Attachments Removed	Quantitative	100% Field inspection by BVES staff and work order review by engineering

Safety and Technical Upgrades to Lake Substation	GD_13	% of Project Completed	Quantitative	100% Field inspection by BVES staff and work order review by engineering
Partial Safety and Technical Upgrades to Village Substation	GD_14	% of Project Completed	Quantitative	100% Field inspection by BVES staff and work order review by engineering
Equipment maintenance and repair	GD_15	% of Assigned Budget	Quantitative	Utility Engineer and Wildfire Mitigation Supervisor reviews maintenance records and budget
Asset Quality assurance / quality control	GD_16	Number of Asset QCs on WMP Work	Quantitative	Utility Engineer and Wildfire Mitigation Supervisor reviews all asset QCs on WMP work
Asset Open work orders	GD_17	90% or more of work orders completed on schedule for the year	Quantitative	Wildfire Mitigation & Reliability Engineer reviews all asset work orders in asset enterprise system
Equipment Settings to Reduce Wildfire Risk	GD_18	% of EPSS Plan Achieved	Quantitative	Management reviews EPSS plan progress with Utility Engineer and Wildfire Mitigation Supervisor
Grid Response Procedures and Notifications	GD_19	Review Grid Procedures and Update Annually	Qualitative	Management verifies plans are reviewed and updated as applicable.
Minor Undergrounding Upgrades Projects	GD_2	% of Assigned Budget	Quantitative	100% Field inspection by BVES staff and work order review by engineering
Personnel Work Procedures and Training in Conditions of Elevated Fire Risk	GD_20	Conduct Training and Review Procedures for Elevated Fire Risk Conditions	Qualitative	Management verifies plans are reviewed and updated as applicable.
Asset Workforce Planning	GD_21	Evaluate annually workforce training and adequacy	Qualitative	Management verifies workforce training and adequacy evaluation conducted annually
Detailed Inspections	GD_22	Circuit Miles Inspected	Quantitative	Wildfire Mitigation & Reliability Engineer reviews all inspection results

Patrol Inspections	GD_23	Circuit Miles Inspected	Quantitative	Wildfire Mitigation & Reliability Engineer reviews all inspection results
UAV Thermography Inspections	GD_24	Circuit Miles Inspected	Quantitative	Wildfire Mitigation & Reliability Engineer reviews all inspection results
UAV HD Photography/Videography Inspections	GD_25	Circuit Miles Inspected	Quantitative	Wildfire Mitigation & Reliability Engineer reviews all inspection results
3rd Party Ground Patrol Inspections	GD_26	Circuit Miles Inspected	Quantitative	Wildfire Mitigation & Reliability Engineer reviews all inspection results
Intrusive Pole Inspections	GD_27	# of Poles Tested	Quantitative	Utility Engineer and Wildfire Mitigation Supervisor reviews all inspection results
Substation inspections	GD_28	# of Substations Inspected	Quantitative	Utility Engineer and Wildfire Mitigation Supervisor reviews all substation inspection results
Covered Conductor Replacement Project (Pole Assessment)	GD_3	# of Poles Replaced or Reinforced	Quantitative	100% Field inspection by BVES staff and work order review by engineering
Evacuation Route Hardening Project	GD_4	# of Poles Hardened with Wire Mesh Wrap	Quantitative	100% Field inspection by BVES staff and work order review by engineering
Traditional overhead hardening	GD_5	% of Assigned Budget	Quantitative	100% Field inspection by BVES staff and work order review by engineering
Bear Valley Solar Energy Project	GD_6	% of Project Completed	Quantitative	100% Field inspection by BVES staff and work order review by engineering
Bear Valley Energy Storage Project	GD_7	% of Project Completed	Quantitative	100% Field inspection by BVES staff and work order review by engineering

Switch and Field Device Automation	GD_8	# of switches connected to SCADA	Quantitative	100% Field inspection by BVES staff and work order review by engineering
Capacitor Bank Upgrade Project	GD_9	# of units replaced	Quantitative	100% Field inspection by BVES staff and work order review by engineering
Risk Methodology and Assessment	RMA_1	Number of Daily Model Runs	Quantitative	Electric Distribution Systems Engineer verifies data accessibility
Advanced weather monitoring and weather stations	SAF_1	Number of Weather Stations Serviced	Quantitative	Utility Engineer and Wildfire Mitigation Supervisor reviews maintenance records
Advanced weather monitoring and weather stations	SAF_1	Integrate Environmental Monitoring Network as a standard feed into the Distribution Management Center	Qualitative	Utility Engineer and Wildfire Mitigation Supervisor assess level of integration by direct observation of Distribution Management Center Operations
Install Fault Indicators	SAF_2	% of Installed FI's Serviced	Quantitative	Utility Engineer and Wildfire Mitigation Supervisor reviews maintenance records
Install Fault Indicators	SAF_2	Integrate FIs as a standard feed into the Distribution Management Center	Qualitative	Utility Engineer and Wildfire Mitigation Supervisor assess level of integration by direct observation of Distribution Management Center Operations
Online Diagnostic System	SAF_3	Number of circuits installed on per year.	Quantitative	100% Field inspection by BVES staff and work order review by engineering
Online Diagnostic System	SAF_3	Conduct annual review and evaluation of Online Diagnostic system database of system detections	Qualitative	Management reviews results of annual review and evaluation of Online Diagnostic system database of system detections

Autonomous Monitoring of Power Line Infrastructure	SAF_4	% of Installed Sensors Serviced	Quantitative	Utility Engineer and Wildfire Mitigation Supervisor reviews maintenance records
Autonomous Monitoring of Power Line Infrastructure	SAF_4	Integrate issue as a standard feed into the Distribution Management Center	Qualitative	Utility Engineer and Wildfire Mitigation Supervisor assess level of integration by direct observation of Distribution Management Center Operations
ALERT Wildfire Cameras	SAF_5	Number of ALERTWildfire Cameras Evaluated by BVES in Operability and Coverage Review	Quantitative	Management reviews operability report for each ALERTWildfire Camera evaluated
ALERT Wildfire Cameras	SAF_5	Provide assistance as requested by ALERT Wildfire Consortium to maintain, upgrade, and/or expand ALERT Wildfire Cameras covering BVES Service Area	Qualitative	Management reviews assistance requested vs assistance provided
Weather forecasting	SAF_6	Percent Time Each Year Weather Stations are Operational	Quantitative	Management reviews weather station operational availability report
Weather forecasting	SAF_6	Maintain WFA-E Capability and Weather Consultant Coverage for Each Year	Qualitative	Management reviews WFA-E availability and weather reports submitted by weather consultant
Fire potential index	SAF_7	FPI Model Domain Size in Mi^2	Quantitative	Electric Distribution Systems Engineer verifies FPI Model Domain Size in Mi^2
Fire potential index	SAF_7	Integrate FPI as a standard feed into the Distribution Management Center	Qualitative	Utility Engineer and Wildfire Mitigation Supervisor assess level of integration by direct observation of Distribution

				Management Center Operations
Detailed Inspections	VM_1	Circuit Miles Inspected	Quantitative	Wildfire Mitigation & Reliability Engineer reviews all inspection results
Pole clearing	VM_10	# of Poles Cleared	Quantitative	100% Field inspection by arborist
Wood and slash management	VM_11	Wood & slash removed per VM Contract	Qualitative	100% Field inspection by arborist
Substation defensible space	VM_12	# of Substations Cleared	Quantitative	Substation Technician conducts 100% inspection
Emergency response vegetation management	VM_13	Review Vegetation Management Emergency Response Procedures Annually	Qualitative	Management verifies plans are reviewed and updated as applicable.
Post-fire service restoration	VM_14	Review Post-fire service restoration procedures annually	Qualitative	Management verifies plans are reviewed and updated as applicable.
Vegetation Management Quality assurance / quality control	VM_15	# of VM QCs Performed	Quantitative	Management verifies number of VM QC conducted
Vegetation Management Open work orders	VM_16	90% or more of work orders completed on schedule for the year	Quantitative	Wildfire Mitigation & Reliability Engineer reviews all VM work orders in VM enterprise system
Vegetation Management Workforce planning	VM_17	Evaluate annually workforce training and adequacy	Qualitative	Management verifies workforce training and adequacy evaluation conducted annually
Patrol Inspections	VM_2	Circuit Miles Inspected	Quantitative	Wildfire Mitigation & Reliability Engineer reviews all inspection results
UAV HD Photography/Videography Inspections	VM_3	Circuit Miles Inspected	Quantitative	Wildfire Mitigation & Reliability Engineer reviews all inspection results
LiDAR Inspections	VM_4	Circuit Miles Inspected	Quantitative	Wildfire Mitigation & Reliability Engineer

				reviews all inspection results
3rd Party Ground Patrol Inspections	VM_5	Circuit Miles Inspected	Quantitative	Wildfire Mitigation & Reliability Engineer reviews all inspection results
Substation inspections	VM_6	# of Substations Inspected	Quantitative	Utility Engineer & Wildfire Mitigation Supervisor review all inspection results
Satellite Imaging Inspections	VM_7	Inspection of Entire Service Area	Quantitative	Wildfire Mitigation & Reliability Engineer reviews all inspection results
Fall-in Mitigation and High-risk Species	VM_8	# of trees remediated or removed to prevent fall-in	Quantitative	100% Field inspection by arborist
Clearance	VM_9	Circuit Miles Cleared	Quantitative	100% Field inspection by arborist
Wildfire Mitigation Strategy Development	WMSD_1	Develop WMP Updates or WMP as required by OEIS Schedule	Qualitative	Regulatory Affairs verifies compliance

Code and Title: BVES-23B-02 (BVES-23-02). PSPS and Wildfire Risk Trade-Off Transparency

Description: BVES does not provide adequate transparency regarding PSPS and wildfire risk trade-offs, or how it uses risk ranking and risk buy-down to determine risk mitigation selection.

Required Progress: In its 2026-2028 Update, BVES must describe:

- How it prioritizes PSPS risk in its risk-based decisions, including trade-offs between wildfire risk and PSPS risk.
- How the rank order of its planned mitigation initiatives compares to the rank order of mitigation initiatives ranked by risk buy-down estimate, along with an explanation for any instances where the order differs.

Section and Page Number of Any Improvements: Section 5.2.2.2 (p. 44), Section 5.5.1.1 (p. 60), Section 5.5.2 (p. 61), Section 6 (p. 71), and Section 7 (p. 100)

BVES Response: Bear Valley is still working with DIREXYON to develop the ability to calculate PSPS risk. While Bear Valley had hoped complete this by the end of 2024, the model is still in development and not expected to be fully operation until the end of 2025.

Since BVES has been running FPI on a daily basis, BVES has noticed a very high correlation of relative risk from Wildfire and PSPS. Once BVES fully incorporates the DIREXYON model in 2025, BVES will evaluate both wildfire and PSPS based models to determine Utility Risk.

However, Bear Valley is using the FireSight (Technosylva model) to prioritize grid hardening initiatives, which not only have ignition risk reduction impact but they also closely correlate to reduction of PSPS risk. In fact, Bear Valley's grid hardening plan based on FireSight risk prioritization, will result in all of Bear Valley's areas designated as most at risk of PSPS being hardened by the end of 2028. The following are the area's most at risk of PSPS:

- Holcomb 4kV (North Shore Big Bear City Area): Gird hardening planned for 2026.
- Boulder 4kV (Boulder Bay Area): Gird hardening planned for 2026 and 2028.
- North Shore 4kV (Fawnskin Area): Gird hardening planned for 2027.
- Pioneer 4kV (Baldwin Lake Area): Gird hardening planned for 2027.

BVES has factored in a PSPS consequence surrogate based on Technosylva RAVE information (See Section 5.2.2.2) as input to overall utility risk.

Furthermore, Bear Valley will prioritize implementing EPSS on the areas designated as most at risk of PSPS.

Code and Title: BVES-25U-01 (BVES-23-03). 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: BVES and the other IOUs have participated in past Energy Safety-sponsored scoping meetings on these topics but have not reported other collaboration efforts.

Required Progress: BVES and the other IOUs must participate in all Energy Safety-organized activities related to best practices for:

- Inclusion of climate change forecasts in consequence modeling.
- Inclusion of community vulnerability in consequence modeling.
- Utility vegetation management for wildfire safety.

BVES must collaborate with the other IOUs on developing the above-mentioned best practices. In their 2025 Updates, the IOUs (not including independent transmission operators) must provide a status update on any collaboration with each other that has taken place, including a list of any resulting changes made to their WMPs since the 2023-2025 WMP submission.

[2023-2025 WMP: Discussed in Section 7, “Wildfire Mitigation Strategy Development”; 8.2, “Vegetation Management and Inspections.”]

Section and Page Number of Any Improvements: Section 5 (p. 35) and Section 13.2 (p. 303)

BVES Response: Bear Valley collaborates with the other IOUs through monthly meetings (WMP Joint IOU 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.

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.

Inclusion of climate change forecasts in risk consequence modeling: Bear Valley will continue to participate in all Energy Safety-organized activities related to best practices for inclusion of climate change forecasts in consequence modeling.

Inclusion of community vulnerability in consequence modeling: Bear Valley will continue to participate in all Energy Safety-organized activities related to best practices for inclusion of community vulnerability in consequence modeling.

Utility vegetation management for wildfire safety: Bear Valley will continue to participate in all Energy Safety-organized activities related to best practices for utility vegetation management for wildfire safety.

Code and Title: BVES-23-07. Risk Informed Prioritization of Grid Hardening Installation

Description: BVES's current covered conductor scope does not demonstrate proper decision-making considerations regarding project prioritization.

Required Progress: In its 2026-2028 Base WMP, BVES must:

- Explain how it is focusing its covered conductor and other grid hardening projects in the areas of highest risk based on the most recent and available WRRM output.
- Adjust its targets as needed based on its analysis.

Section and Page Number of Any Improvements: Section 5.2.2.2 (p. 44), Section 5.5.1.1 (p. 60), Section 5.5.2 (p. 61), Section 6 (p. 71), and Section 8.2.1 (p. 117).

BVES Response: Bear Valley is using the FireSight (Technosylva model) to prioritize grid hardening initiatives, which not only has ignition risk reduction impact but also closely correlates to reduction of PSPS risk. WRRM is the former name of FireSight.

Bear Valley's grid hardening plan based on FireSight risk prioritization, will result in all of Bear Valley's areas designated as having the highest risk (98th percentile acres burned) will be hardened with covered conductors by the end of 2028. The following are the area's designated as having the highest risk (98th percentile acres burned):

- Holcomb 4kV (North Shore Big Bear City Area): Gird hardening planned for 2026.
- Boulder 4kV (Boulder Bay Area): Gird hardening planned for 2026 and 2028.
- North Shore 4kV (Fawnskin Area): Gird hardening planned for 2027 and 2028.
- Pioneer 4kV (Baldwin Lake Area): Gird hardening planned for 2027.
- Clubview 4kV (Moonridge Area): Gird hardening planned for 2028.

Targets are adjusted based on the location of the circuit (flat terrain vs. mountainous), location to first responders, length of circuit. This year BVES introduced a surrogate for PSPS vulnerability and exposure that was also considered in the prioritization.

Code and Title: BVES-23-08. Covered Conductor Mitigation Selection

Description: BVES's current covered conductor scope does not demonstrate proper decision-making considerations regarding mitigation selection.

Required Progress: In its 2026-2028 Base WMP, BVES must:

- Demonstrate how it compares alternative initiatives, mitigations, and combinations of mitigations to covered conductor, and provide the analyses used for such comparisons.
- Adjust its targets as needed based on its analysis.

Section and Page Number of Any Improvements: Section 8.2.1 (p. 117) and Section 8.2.2 (p. 120)

BVES Response: Bear Valley is using the FireSight (Technosylva model) to prioritize where to conduct grid hardening initiatives, which not only have ignition risk reduction impact but they also closely correlate to reduction of PSPS risk.

In the long-term for the HFTD, there are basically two effective means of grid hardening: (1) replace bare conductors with covered conductors or (2) convert bare conductor overhead facilities to underground facilities. In selecting replace bare conductors with covered conductors, Bear Valley considered the following:

- <u>Ease of construction</u>: Bear Valley's service area is very rocky and has significant tree roots in the terrain making installation of underground facilities very challenging; whereas replacing bare conductors has less intrusive construction with respect to the terrain (limited to some pole replacements).
- <u>Less complicated planning</u>: Converting overhead facilities to underground facilities requires significant planning and construction design; whereas replacing bare conductors with covered conductors simply requires assessing existing pole structures and replacing some poles to accommodate the covered conductors.
- <u>Less cost</u>: Undergrounding in Bear Valley's difficult terrain is significantly more expensive that installing covered conductors. Undergrounding costs can reach 5 to 10 times the cost of overhead construction.
- <u>Permitting ease</u>: Converting overhead facilities to underground facilities in the Bear Valley service area would require significant permitting with various permitting entities including the U.S. Sorest Service, Caltrans, California Department of Fish and Wildlife, California Department of Water Resources, City of Big Bear Lake and County of San Bernardino; whereas replacing bare conductors with covered conductors without changing the existing footprint of the facilities reduces the permitting requirements significantly.
- <u>Less time to reduce risk</u>: By selecting to replace bare conductors with covered conductors instead of converting overhead facilities to underground facilities, Bear Valley has significantly reduced the time to achieve significant ignition and PSPS risk reduction. Just

the planning, design and permitting for undergrounding can take 3-5 years before an underground trench can be dugout. Furthermore, the pace of reconductoring overhead facilities is much faster than the pace of installing underground facilities.

While underground facilities provide the “ultimate” risk reduction solution, covered conductors substantially reduce the risk of ignition and PSPS. The major advantage of covered conductors is that they cost significantly less per circuit mile than underground facilities yet the marginal gain in risk reduction by utilizing underground facilities instead of covered conductors is not nearly as significant. The PSPS thresholds for circuits with covered conductors increase significantly. Bear Valley’s analysis of the weather on high-risk days over the last ten years, indicates that the covered conductor PSPS thresholds have never been experienced in the BVES service area. Additionally, Bear Valley has not found an instance of an ignition due to failed covered conductors. Bear Valley has not ever experienced an outage due to failed covered conductors.

For the above reasons, Bear Valley considers covered conductors a prudent and reasonable solution for its service area and stakeholders.

Code and Title: BVES-25U02 (BVES-23-11). Covered Conductor Inspections and Maintenance

Description: BVES does not incorporate checks in its inspection programs that address failures specific to covered conductor. BVES must tailor its inspection practices to address failure modes specifically related to covered conductor.

Required Progress: In its 2026-2028 Base WMP, BVES must provide:

- A timeline for including covered conductor surface damage checks in its inspection processes.
- A timeline for developing a strategy to address water intrusion and including water intrusion checks in its inspection processes.

If BVES has reached the final milestone of both required timelines at the time of its 2026-2028 Base WMP submission, it must provide the inspection checklists as attachments to its WMP submission.

Section and Page Number of Any Improvements: Section 8.4.4 (p. 151)

BVES Response:
Surface Damage Checks During Inspection: Bear Valley was advised by the manufacturer that periodic visual inspections that are normally conducted on overhead systems (such as patrols and detailed inspections) should include looking for significant discoloration, bubbling, change in sag with-in the conductor span between phases and separation of the outer coating from the covered conductor cable, and signs of abrasions that penetrate through the outer coating.

These instructions have been provided to the BVES Field Inspector, who performs Detailed Inspections (GD_22) and Patrol Inspections (GD_23) asset inspections. Bear Valley's contractors who perform the following asset inspections have also been provided these instructions:

- UAV Thermography Inspections (GD_24)
- UAV HD Photography/Videography Inspections (GD_25)
- 3rd Party Ground Patrol Inspections (GD_26)

Bear Valley will be issuing a revision to its written procedures that govern Detailed Inspections and Patrol Inspections by the end of June 2025.

Water Intrusion and Including Water Intrusion Checks In Its Inspection Processes: Signs of water intrusion are significant discoloration, bubbling, change in sag with-in the conductor span between phases and separation of the outer coating from the covered conductor cable, which are included in the inspection instructions discussed above.

The covered conductors that Bear Valley is currently installing includes a water blocker to prevent water intrusion.

Bear Valley keeps track of where covered conductors were installed that did not have the water blocker. The inspectors for the inspections discussed above are alerted to pay particular attention to these areas in their inspections.

BVES participates in the joint utilities workshop on covered conductors and will continue to exchange information in this area with other utilities. BVES will attend T&D conferences and review T&D literature and periodicals on the latest in covered conductor operations and maintenance.

Code and Title: BVES-25U-03 (BVES-23-13). Asset Inspection QA/QC Program

Description: BVES has not implemented a QA/QC process for its asset inspections.

Required Progress: In its 2026-2028 Base WMP, BVES must update its written QA procedures for each inspection type. The written process must:

- Include annual audits.
- Specify a statistically relevant sample size to audit.
- Require audits be performed by a person/persons other than the original inspector.
- Track audit pass rates.

Section and Page Number of Any Improvements: Section 8.5 (p. 156)

BVES Response: Bear Valley is updating its written QA/QC process for its asset inspections to meet the following requirements listed in the table below. These written requirements will be issued by the end of June 2025.

Asset Inspection	Annual Audit Conduct by	Audit Sample Size	Pass Rate	Field Check
Detailed Inspections (GD_22)	Wildfire Mitigation & Reliability Engineer	100% of results	90%	5% of inspected facilities
Patrol Inspections (GD_23)	Wildfire Mitigation & Reliability Engineer	100% of results	90%	5% of inspected facilities
UAV Thermography Inspections (GD_24)	Wildfire Mitigation & Reliability Engineer	100% of results	90%	100% of reported discrepancies
UAV HD Photography/Videography Inspections (GD_25)	Wildfire Mitigation & Reliability Engineer	100% of results	90%	100% of reported discrepancies
3rd Party Ground Patrol Inspections (GD_26)	Wildfire Mitigation & Reliability Engineer	100% of results	90%	100% of reported discrepancies
Intrusive Pole Inspections (GD_27)	Utility Engineer and Wildfire Mitigation Supervisor	100%	90%	100% of reported discrepancies
Substation inspections GD_28	Utility Engineer and Wildfire Mitigation Supervisor	100%	90%	100% of reported discrepancies

An QA annual audit of each asset inspection includes a 100% review of the asset inspection results and how the inspection was conducted. All asset inspection discrepancies are field checked. Additionally, a completeness check is performed to ensure the inspection included all of the facilities designated to be inspected. An audit pass rate of 90% is designated. Scores below 90% indicate an inspection process problem. If the score is below 90%, the root causes are investigated by the Wildfire Mitigation & Reliability Engineer and Utility Engineer and

Wildfire Mitigation Supervisor and they are addressed with the persons performing the inspection. The failing inspections are paused until the issues are resolved. Also, depending on the severity of the issues, the all or part of the inspection may be directed to be conducted again by the Wildfire Mitigation & Reliability Engineer. All audit discrepancies are reviewed with the applicable inspector(s).

For Detailed Inspections (GD_22) and Patrol Inspections (GD_23), 5% of the inspected facilities will be checked by a qualified inspector other than the person performing to original inspection as a QC check on these inspections. A pass rate of 90% is designated for these checks. If the checks result in a score below 90%, the root causes are investigated by the Wildfire Mitigation & Reliability Engineer and Field Operations Supervisor and they are addressed with the Field Inspector. The failing inspections are paused until the issues are resolved. Also, depending on the severity of the issues, the all or part of the inspection may be directed to be conducted again by the Wildfire Mitigation & Reliability Engineer. All QC discrepancies are reviewed with the Field Inspector.

Code and Title: BVES 25U-04 [BVES-23-15]. Reliability Impacts of Fast Trip Settings

Description: BVES has not demonstrated an understanding of the reliability impacts of using fast trip settings.

Required Progress: In its 2026-2028 Base WMP, BVES must provide:

- A complete list of recommendations provided by the consultant.
- A timeline for the incorporation of each recommendation.
- Justification for any recommendations BVES does not plan to adopt.

Section and Page Number of Any Improvements: Section 8.7.1 (p. 165)

BVES Response:

Recommendations Provided By the Consultant: In 2024, Bear Valley engaged an expert power distribution consultant firm to perform an evaluation of the Bear Valley's device setting policy and provide recommendations to improve settings to reduce the probability of ignitions. The consultant completed the study of BVES's protective settings on 10 circuits sample circuits (3 sub-transmission circuits and 7 distribution circuits) at the end of January 2025. Key findings are:

- Not all protection devices have 100% coverage for phase and ground faults, which results in long clearing times at the end of zones of protection.
- To have a protection scheme that will cover 100% of the required circuit, the settings will need to be set more sensitively to extend the circuit coverage.
- The study proposes an Enhanced Power Line Safety Setting (EPSS) philosophy as follows:
    - The goal of Enhanced Power Line Safety Setting (EPSS) protection is to trip and clear faults as fast as possible on the entirety of the protected circuit. To do so, this protection sacrifices circuit coordination in favor of sensitivity and fast tripping.
    - The EPSS protection should be set as follows:
        - Reclosing: All reclosing attempts disabled. Devices will be single trip to lockout.
        - Phase Sensitivity: 1.5 times peak loading ≤ Minimum Phase Trip (Pickup) < EOLLL /2 (50% protection reach margin). Use Phase Fast curve = TCC 101.
        - Ground Sensitivity: 1.5 times peak load imbalance ≤ Minimum Ground Trip (Pickup) < EOLSLG /3 (33% protection reach margin). If load imbalance data is not available: Ground minimum trip > 30% of historical peak load phase current imbalance at the protection device. Ground Fast curve = TCC 101.
        - Use of the 101 time current curve ensures faults should clear within 12.0 cycles (0.2 seconds).

- The study proposes the following implementation strategy:

  - To improve circuit coverage for fast tripping and sensitivity, implement the following device setting changes:

    - 1) Enable ground overcurrent elements in any protection devices where the protection is available but turned off. This should be enabled on all 4.16 kV distribution circuits. This will allow much greater sensitivity for single line to ground faults.
    - 2) Standardize and update fast curves across all 4.16kV devices. In “EPSS” setting profiles, for the initial fast trip update the curves to the standardized TCC 101 curve. Special focus should be given to those devices that are presently using SEL U5 or inverse curves.
    - 3) While updating the fast curves, it would be most efficient to also re-evaluate and update pickup settings per the criteria contained in the EPSS Philosophy.
    - 4) Ensure reclose attempts are disabled in EPSS setting profile.

  - Having pickup setting flexibility and ground overcurrent protection is key for EPSS. Oil reclosers may not offer these capabilities. It is recommended to replace any oil recloser units with electronically controlled reclosers.
  - For instances where device pickups cannot satisfy both protection reach margins and load security margins, consider installing an additional downline series recloser. The new recloser should shorten the zone of protection bringing the EOL fault location closer. The new recloser should also see a smaller peak load current, allowing it to have a more sensitive pickup.

<u>Timeline for the Incorporation of Each Recommendation</u>: Based on the results of the study, Bear Valley is conducting the following:

- Developing an EPSS operational policy. This is to be completed by end of Q2 2025.

  - Which circuits should have EPSS capability?
  - When should EPSS be invoked (e.g., when FPI is “High” or higher)?
  - How is EPSS implemented (e.g., operational direction and connectivity to devices)?

- Developing a circuit-by-circuit plan to implement EPSS recommendations in coordination with the EPSS operational policy.

  - For each circuit identify any equipment, hardware, software, and/or connectivity gaps to implementing EPSS and develop a plan to close the gaps on a risk-based priority.
  - For each circuit develop EPSS settings for protection devices on the circuit.
  - This planning action is to be completed by the end of Q3 2025.

- EPSS Implementation:
  - Update internal procedures and conduct training with staff on EPSS policy.
  - For circuits that are ready to implement EPSS, when conditions warrant implement EPSS.
  - For circuits requiring equipment, hardware, software, and/or connectivity to implement EPSS, pursue upgrading these circuits on a risk-based priority schedule and as each circuit becomes EPSS capable, implement EPSS when conditions warrant EPSS.
  - Implementation should begin in Q4 2025 and the goal is to be fully implemented by the end of 2027.

<u>Justification For Any Recommendations BVES Does Not Plan To Adopt</u>: Bear Valley plans to adopt the recommendations of the study.

Code and Title: BVES-23-16. Vegetation Management Quality Control Personnel Qualifications

Description: In its response to BVES-22-16, Vegetation Management Quality Control Personnel Qualifications, BVES has not demonstrated that it has considered alternative staffing for its vegetation management quality control checks. BVES has not shown that it has properly identified trained and qualified personnel for its vegetation quality control checks.

Required Progress: In its 2026-2028 Base WMP, BVES must:

- Present a plan to improve the utility vegetation management-related qualifications of its QC check personnel.
- Explain and provide the decision-making process on its consideration of alternative staffing for its vegetation management QC checks, including consideration of employing or contracting with certified arborists or registered professional foresters to perform these checks.

Section and Page Number of Any Improvements: Section 9.13 (p. 227)

BVES Response:
Plan To Improve The Utility Vegetation Management-Related Qualifications of Its QC Check Personnel:
Currently, Bear Valley is fully staffed with appropriately qualified personnel to meet all of its vegetation management QC check requirements.

Bear Valley retains a certified arborist forester embedded in its staff who performs 100 percent QC field checks of all pruning and removal activities. Additionally, Bear Valley assigns appropriately qualified and experienced staff to conduct QC checks at randomly selected areas where vegetation management crews have conducted pruning and removal activities. These QC checks are conducted by qualified staff designated in the BVES Vegetation Management Procedures Manual.

Decision-Making Process On Its Consideration Of Alternative Staffing For Its Vegetation Management QC Checks: Currently, Bear Valley is not considering alternative staffing for its vegetation management QC checks. Bear Valley is fully staffed with appropriately qualified personnel to meet all of its vegetation management QC check requirements.

Code and Title: BVES-25U-05. Vegetation Management Remote Sensing Evaluation

Description: As BVES's use of satellite-based inspection matures, BVES should continue to consider resource-use efficiency and effectiveness of its various remote sensing methods for vegetation management.

Required Progress: In its 2026-2028 Base WMP, BVES must:

- List the data outputs from its satellite and LiDAR inspections.
- Describe how BVES will use those data outputs to improve vegetation management-related outcomes over the 2026-2028 WMP cycle.
- Evaluate and compare the costs, benefits, and effectiveness of using:
  - Ground-based inspections.
  - LiDAR with ground-based inspections.
  - Satellite-based inspections with ground-based inspections.
  - LiDAR and satellite-based inspections with ground-based inspections.

Section and Page Number of Any Improvements: Section 9.2.4 (p. 192) and Section 9.2.7 (p. 200)

BVES Response:

<u>Data Outputs From Its Satellite And Lidar Inspections</u>: The satellite inspection (VM_7) provides the following for each line segment:

- Criticality score (measure of vegetation risk contacting power lines)
- Hazard tree risk
- Grow-in risk

LiDAR surveys (VM_4) provides detailed data of how far vegetation is from the power lines across the entire overhead system. Essentially, BVES receives a three-dimensional digital map of all possible encroachments. Encroachment thresholds are set base on BVES's minimum clearance specifications and the data is searched for instances where clearance specifications are encroached.

<u>Data Outputs To Improve Vegetation Management-Related Outcomes</u>:
The satellite inspection is relatively quick inspection (1 day) with processing taking up to a month. BVES conducts this satellite inspection when all of the deciduous trees regain their leaves but before the peak of fire season in order to get a quick vegetation assessment. This allows BVES to re-prioritize vegetation pruning and removal work, if necessary, prior to the fire season.

The LiDAR is a very detailed inspection. LiDAR is conducted using both drones and truck mounted sensors (to get under the canopy for distribution lines). Data acquisition takes 1-2 weeks but processing of the inspection results can take 1-2 months. The detailed inspection results provide a very accurate quantitative listing of possible encroachments and their exact locations. Each possible encroachment is field inspected and trimmed, if necessary.

Evaluate and Compare the Costs, Benefits, and Effectiveness: The table below provides a comparison of costs, benefits and effectiveness, for the following inspection groups:

- Ground-based inspections.
- LiDAR with ground-based inspections.
- Satellite-based inspections with ground-based inspections.
- LiDAR and satellite-based inspections with ground-based inspections

Inspections	**Cost $ thousands (2026)**	**Benefit**	**Effectiveness**
Ground-based inspections only (these are: Detailed Inspections (VM_1), Patrol Inspections (VM_2) and 3rd Party Ground Patrol Inspections (VM_5))	$ 226.0	Provide eyes on overhead facilities, which allows the obvious encroachments to be detected. Also, ground-based inspection are blocked by tree the canopy that exists above distribution circuits.	Least effective
LiDAR with ground-based inspections	$ 384.5	Same benefits of ground-based inspections above plus LiDAR provides accurate quantitative listing of possible encroachments, which might otherwise be missed by visual inspections. Truck mounted sensors avoid canopy blockage that exists above distribution circuits.	Second most effective
Satellite-based inspections with ground-based inspections	$ 266.0	Benefits of ground-based inspections above plus quick satellite inspection results providing criticality score, hazard tree risk, and grow-in risk for each segment. Lacks the thoroughness and accuracy of LiDAR. Satellite inspection is somewhat blocked by the canopy that exists above distribution circuits	Third most effective
LiDAR and satellite-based inspections with ground-based inspections	$ 424.5	Benefits of ground-based, LiDAR and satellite inspections above.	Most effective group of inspections.

The thoroughness and precision of the LiDAR inspection makes it the most effective vegetation inspection. Bear Valley's entire service area is in the HFTD in a heavily treed mountainous area. The canopy above distribution lines poses a challenge to inspection from above. Therefore, Bear Valley has found that the combination of ground-based inspections (Detailed Inspections

(VM_1), Patrol Inspections (VM_2) and 3rd Party Ground Patrol Inspections (VM_5)), LiDAR inspections (VM_4) and complimented with satellite inspection (VM_7) is the most effective approach to ensuring encroachments are properly identified, managed and resolved.

Appendix E. **Referenced Regulations, Codes, and Standards**

Name of Regulation, Code, or Standard	Brief Description
Public Utilities Code section 8386	Statute related to electrical lines and equipment.
Public Utilities Code section 768.6	Statute related to emergency and disaster preparedness plans.
Public Resources Code section 4292	Statute related to firebreaks near a utility pole.
R.20-07-013	Regulation related to risk-based decision- making framework used to minimize safety risks.
R.15-06-009	Regulation related to a response to an attack on the system.
D.19-04-020	Decision related to sharing the safety performance metrics reports that document the previous year's data with the Commission.
D.17-12-024	Decision related to regulations to enhance fire safety, such as Fire-Threat Maps.
D.21-05-019	Decision related to emergency and disaster preparedness plans and notification/reporting of electric service outages.
D.21-06-034.53	Decision related to de-energization of power lines in dangerous conditions.
General Order 95	Standards for Overhead Electric Line Construction.
General Order 128	Standards for Construction of Underground Electric.
General Order 165	Standards for electric distribution and transmission facilities.
General Order 166	Standards for Operation, Reliability, and Safety during Emergencies and Disasters.
General Order 174	Standards for Electric Utility Substations
Title 14 section 29200	Regulation regarding a record's "confidential designation".
Government Code § 8593.3	Government of the State of California, California Emergency Services Act, Accessibility to Emergency Information and Services.
California Standardized Emergency Management Systems (SEMS)	Manages emergencies to coordinate across all levels of utility and governments.
National Incident Management System (NIMS)	Incident management structure to maintain chain of command and span of control principles for crisis management.

Appendix F. **BVES Emergency Response and Disaster Plan**

Bear Valley Electric Service, Inc.

Emergency & Disaster Response Plan

March 31, 2022

Approved by: ____

Paul Marconi, President, Treasurer, & Secretary

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List of Appendices

1. **<u>Purpose and Introduction</u>.** The Emergency & Disaster Response Plan (EDRP) is provided to all Bear Valley Electric Service, Inc. ("BVES") employees to ensure an efficient, effective and uniform response during an emergency situation. BVES recognizes the importance of an integrated EDRP in order to safely provide for the energy needs of our customers and the requirements of our stakeholders in the event of an emergency.

The EDRP outlines BVES' philosophy and procedures for managing major emergencies that may disrupt electric service to our customers or threaten the health and safety of the people in the communities we serve. The EDRP further establishes the structure, processes and protocols for the BVES's emergency response and identifies departments and individuals that are directly responsible for that response and critical support services. In addition, it provides a management structure for coordination and deployment of the essential resources necessary for the response.

The EDRP is designed to provide a framework for managing and responding to:

- Large outages
- Numerous smaller outages
- Potential for large outages
- Potential for numerous smaller outages
- Any combination of the above

The EDRP may be invoked as a precautionary measure when there is a strong potential for outages or in response to actual outages. The EDRP is designed to be implemented as needed in conjunction with other procedures, plans, and policies such as:

- Public Safety Power Shutdown Plan
- Wildfire Mitigation Plan
- Field Operations and Engineering Procedures
- Customer Service Procedures
- Other organizations such as State, County, and City Emergency Disaster Plans

The EDRP complies with the requirements set forth in the Public Utilities Commission of the State of California's General Order No. 166, Standards for Operation, Reliability, and Safety during Emergencies and Disasters.

1.1. **Plan Goals.** When an emergency occurs, BVES' response actions are guided by the following overriding emergency goals (in order of priority):

- **Safety:** Protect the life-safety of our customers, employees and the general public.
- **Restoration of Power:** Restore electric service to customers in a safe and timely manner.
- **Communications:** Keep customers, stakeholders, and staff informed.

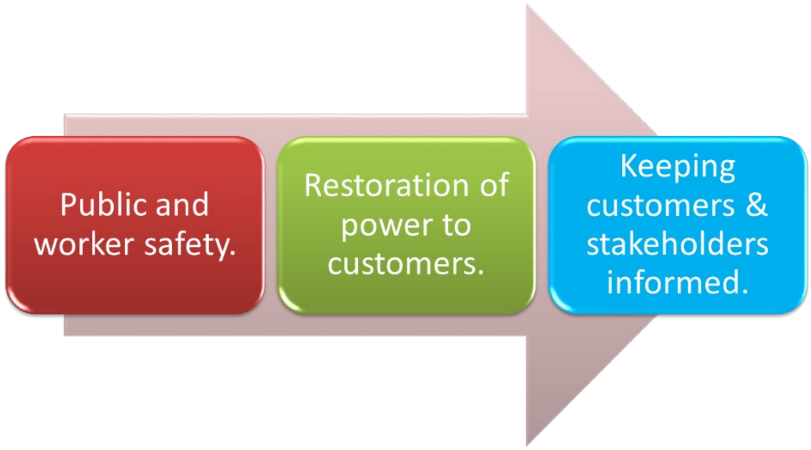

Figure 1-1: EDRP Goals

1.2. **Plan Vision.** BVES strives to meet customer needs through effective risk assessment, mitigation, preparedness, response and communications. Our vision is to achieve excellence in emergency management performance.

1.3. **Plan Policy.** BVES strives to utilize effective emergency management principles that enhance the BVES's ability to provide safe and reliable electric power and its ability to communicate timely and accurate information to customers and stakeholders by:

- Conducting effective risk assessments for operating and business functions;
- Developing appropriate prevention or risk mitigation strategies;
- Implementing comprehensive emergency preparedness programs;
- Responding with appropriate resources to address emergencies;
- Communicating with customers and other stakeholders with timely and accurate information;
- Recovering from events safely and expeditiously; and
- Improving continuously.

Since major outage events and emergencies are rarely similar in all respects, the EDRP is constructed in such a way to provide BVES management with a trained and operationally ready workforce and a response operations process that may be employed as required to deal with the unique aspects of each major outage and emergency event.

The effectiveness of the EDRP is based on BVES' commitment to prepare for, to implement, and to review procedures after each implementation. An after action review process shall facilitate continuous improvement in the BVES's response and restoration processes.

Execution of the appropriate response to affect rapid and safe recovery is dependent upon the scalability of this plan. For example, storm intensities and the number of customers affected vary and, therefore, the level of recovery resources committed to each event is adjusted as appropriate even though the operational concepts remain consistent.

1.4. **Plan Responsibility.** It is the responsibility of all Managers and Supervisors to ensure the EDRP is reviewed by all staff and is updated when appropriate. Specific responsibilities are provided throughout the EDRP.

1.5. **General Overview.** BVES customers receive electric service through an overhead and underground distribution system. Extreme weather events such as heavy rain, hail, snow, ice, lightning, high winds, and/or extreme dry heat may adversely impact the integrity of the distribution system, resulting in occasional interruptions of electric service. The distribution system is also susceptible to damages as a result of major disasters, such as earthquakes, flooding, wildfires, and mud and rock slides. Furthermore, in the interest of public safety, BVES may deem it necessary to proactively de-energize large portions of the distribution system to protect the public; for example, BVES may de-energize circuits or portions of circuits during extreme fire threat weather conditions. BVES normally imports power to its service area via Southern California Edison's (SCE) transmission lines. Therefore, the BVES service area may be susceptible to outages caused by events outside of its services area. All of the above may result in major power outages of varying extent and length depending on the severity of the event. Since electricity is a critical element in our daily lives, prompt restoration is a reasonable customer expectation and a BVES goal. In the case of major disasters, rapid and efficient restoration of power; especially to critical infrastructure, is essential to overall community disaster recovery.

The response to customer outages caused by severe weather events, other disasters or events affecting power delivery to the BVES service area is predicated on recognizing and understanding the magnitude of the event as well as the availability of resources to support the restoration process. This plan has been designed to provide a systematic organized response plan for the purpose of promoting a safe and efficient recovery from any of those conditions. Since the potential of sustaining damages is highest for storm situations, the plan specifically addresses these situations but it may easily be adapted to major outages caused by other disasters or causes.

It is also recognized that no plan can possibly predict and cover every emergency situation. Therefore, the EDRP provides a structure that is based on a set of reasonable assumptions for the most likely emergencies requiring emergency response; but it also provides the BVES's Incident Commander the authority, flexibility, and discretion to alter the BVES's emergency response to tailor it to the specific emergency situation in order to optimize the utilization of BVES resources and to achieve the emergency response goals in an effective and efficient manner.

A critical component of the EDRP is close coordination with stakeholders that depend on BVES's service and assistance for their response actions and who may, also, be able to assist BVES in its response actions. The coordination must occur in developing the plan, training on the plan, executing the plan, and in plan refinements. Some of BVES's major stakeholders include:

- Local officials (City of Big Bear Lake (CBBL) and San Bernardino County)
- State officials (California Public Utilities Commission)
- San Bernardino County Office of Emergency Services (County OES)
- Big Bear Fire Department

- California Department of Forestry and Fire Protection (CAL FIRE)
- U.S. Forest Service
- San Bernardino County Sheriff's Department Big Bear Lake Patrol Station
- California Highway Patrol (CHP) Arrowhead Area
- California Department of Transportation (Caltrans)
- Big Bear Area Regional Wastewater Agency (BBARWA)
- Big Bear City Community Services District (CSD)
- Big Bear Lake Water Department (DWP)
- Big Bear Municipal Water District (MWD)
- Southwest Gas Corporation
- Bear Valley Community Hospital
- Bear Valley Unified School District
- Big Bear Chamber of Commerce
- Big Bear Airport District
- Big Bear Mountain Resort
- Various media and communications companies

Accurate, effective and timely communications with key stakeholders is critical in emergency response and, therefore, it is essential that business relationships be developed before emergency response is necessary. Understanding stakeholders' key staff, contact information, roles and responsibilities, and capabilities are extremely useful in achieving successful emergency response.

1.6. **Definitions.**

Accessible: A condition which permits safe and legal access.

Access and Functional Needs Populations: Refers to those populations with access and functional needs as set forth in Government Code § 8593.3. Access and functional needs population consists of individuals, including but not limited to, individuals who have developmental or intellectual disabilities, physical disabilities, chronic conditions, injuries, limited English proficiency or who are non-English speaking, older adults, children, people living in institutionalized settings, or those who are low income, homeless, or transportation disadvantaged, including, but not limited to, those who are dependent on public transit or those who are pregnant.

Appropriate Regulatory Authority: The agency or governmental body responsible for regulation or governance of the utility.

Critical Customers: Customers requiring electric service for life sustaining equipment.

Emergency or Disaster: An event which is the proximate cause of a major outage, including but not limited to storms, lightning strikes, fires, floods, hurricanes, volcanic activity, landslides, earthquakes, windstorms, tidal waves, terrorist attacks, riots, civil disobedience, wars, chemical spills, explosions, and airplane or train wrecks.

Essential Customers: Customers representing critical infrastructure and Public Safety Partners.

Major Outage: Consistent with Public Utilities Code Section 364, a major outage occurs when 10 percent of the electric utility's serviceable customers experience a simultaneous, non-momentary interruption of service. For utilities with less than 150,000 customers within California, a major outage occurs when 50 percent of the electric utility's serviceable customers experience a simultaneous, non-momentary interruption of service.

Measured Event: A Measured Event is a Major Outage (as defined herein), resulting from non-earthquake, weather-related causes, affecting between 10% (simultaneous) and 40% (cumulative) of a utility's electric customer base. A Measured Event is deemed to begin at 12:00 a.m. on the day when more than one percent (simultaneous) of the utility's electric customers experience sustained interruptions. A Measured Event is deemed to end when fewer than one percent (simultaneous) of the utility's customers experience sustained interruptions in two consecutive 24-hour periods (12:00 a.m. to 11:59 p.m.); and the end of the Measured Event in 11:59 p.m. of that 48-hour period.

Public Safety Partners: First/emergency responders at the local, state and federal level, water, wastewater and communication service providers , community choice aggregators (CCAs), affected publicly-owned utilities (POUs)/ electrical cooperatives, tribal governments, the Commission, CalOES and CAL FIRE.

Safety Standby: Interim activities undertaken to mitigate immediate public safety hazards

Serviceable Customer: A customer prepared and properly equipped to receive service where both the customer's electrical service facilities and those facilities of the utility necessary to serve the customer can be legally and physically accessed in a safe manner.

Sustained Outage: An electric service interruption (0 voltage) lasting greater than 5 minutes.

2. **<u>Emergency Response Organization</u>.** The EDRP requires that in responding to emergencies, the BVES's staff shall be organized largely based on the Standardized Emergency Management System (SEMS) as interpreted by the BVES. The SEMS structure utilized by BVES is a utility compatible Incident Command Structure (ICS) framework designed to manage emergency incidents and events.

2.1. **Standardized Emergency Management System.** SEMS is an emergency preparedness and response system that has been endorsed by the State of California. It is the cornerstone of California's emergency response system and the fundamental structure for the response phase of emergency management. It unifies all elements of California's emergency management community into a single integrated system and standardizes key elements. Additionally, it provides a common structure for all organizations responding to an emergency situation and a means of systematic planning. The benefits of using the SEMS include:

- Use of common terminology among agencies.
- Use of parallel organizational functions among agencies.
- Provides a standard means of systematic planning.

The basic SEMS organization structure is shown in Figure 2-1, SEMS Organization:

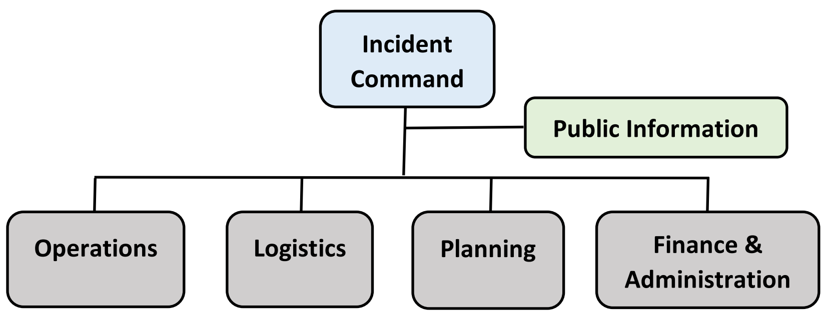

Figure 2-1: SEMS Organization

By organizing the response team along the SEMS structure, the BVES emergency response team is able to coordinate with other government and agencies via their corresponding groups. For example, BVES Operations would coordinate directly with the City of Big Bear Lake Emergency Operations Center or the San Bernardino County OES Operations Groups as applicable. Additionally, when BVES sends a representative to these two centers the representative shall already have a good understanding of the emergency response organization.

2.2. **BVES Emergency Organization.** The organization chart presented below in Figure 2-2, BVES Emergency Organization, provides the BVES Emergency Organization structure for the full mobilization (Level 1) of BVES' staff in responding to emergencies per this plan. It is the intent that this organizational structure would operate out of an Emergency Operations Center (EOC) established by BVES and be sustainable for long-term emergency response activities.

BVES Emergency Organization

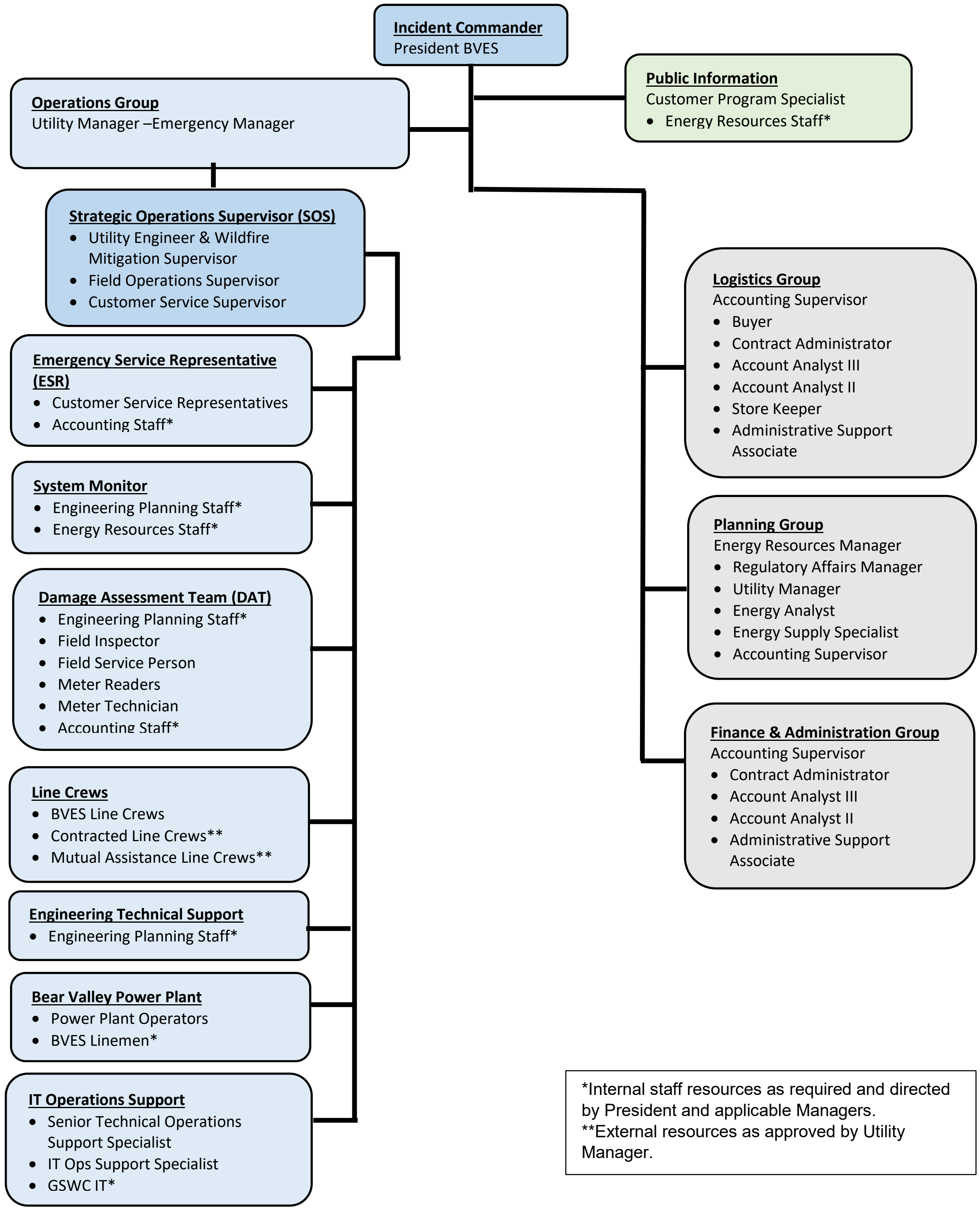

Figure 2-2: BVES Emergency Organization

The specific description of roles and responsibilities for the positions in the BVES Emergency Organization are provided in Section 2.4.

2.3. **BVES Emergency Operations Center (EOC).** An EOC shall be designated for BVES staff use in the event of an emergency. The EOC is the central command and control facility responsible for carrying out the principles of emergency preparedness and emergency response functions described in the EDRP, ensuring public and worker safety, continuity of operations, and timely communications with customers and stakeholders.

An EOC is primarily responsible for strategic direction and operational decisions. Due to the relatively small size of BVES, the Strategic Operations Supervisor (SOS) under the direction of the Operations Group at the EOC shall provide tactical emergency response direction and directly control field assets. The activities under the SOS' management at the EOC shall include all dispatch functions to include customer communications and field operations. For the purpose of the EDRP, when "dispatch" functions are referred to the EOC they are intended for the SOS and supporting team at the EOC.

The common functions of the EOC is to collect, gather and analyze data; make decisions that protect public and worker safety and property; safely maintain and/or restore continuity of operations, within the scope of applicable regulations and laws; and disseminate those decisions to all concerned customers and stakeholders in a timely manner.

2.3.1. The EOC is where the Incident Command, Operations, Planning, Logistics, Financial & Administration, and Public Information groups are located and come together. It serves as the central point for:

- Information gathering and dissemination.
- Directing emergency and restoration operations at both the strategic and tactical level.
- Coordinating with other external agencies and stakeholders.
- Developing and issuing customer and stakeholder communications.
- Evaluating available resources and requesting or relinquishing resources as appropriate.

2.3.2. The EOC shall meet the following requirements:

- Be available for immediate occupancy.
- Have access to backup electrical power.
- Contain access to multiple communication systems such as telephones, mobile phones, VHF radio, internet service, Interactive Voice Response (IVR), etc.
- Be equipped with emergency supplies, system maps and operating information.
- Be capable of sustaining long-term emergency response.

2.3.3. The primary EOC for BVES shall be located at BVES' Main Office at 42020 Garstin Dr., Big Bear Lake, CA 92315 in the "Main Conference Room."

2.3.3.1. The Utility Manager is responsible for ensuring the primary EOC is ready for immediate occupancy. Appendix A, EOC Preparedness and Setup Checklist, provides a list of equipment, capabilities, materials and supplies that should be available to the primary EOC. Some items need not be located in the EOC, but should be in close proximity and readily accessible to EOC staff. The Senior Technical Operations Support Specialist shall maintain

Appendix A up to date as configuration and technology changes are implemented and provide the Administrative Support Associate the latest version of the checklist. The checklist will also be maintained in the EOC.

2.3.3.2. If the primary EOC will not be ready for immediate occupancy, the Utility Manager shall establish an alternate EOC that is ready for immediate occupancy and shall notify BVES staff. Table 2-1 below provides a list of possible alternate EOCs to be considered.

Table 2-1: Possible Alternate Emergency Operation Centers

Location	To Be Considered
Operations & Planning spaces at the BVES Main Office	Primary EOC not available. Also consider this site, when scope of emergency response activation is reduced (such as Level 2 activation) and all or most activity is carried out by Field Operations.
BVES's General Office in San Dimas, California	When evacuation of the BVES service area is ordered.
State or County's Incident Commander's base camp	When the BVES Main Office is not accessible.
Other suitable area designated by the Utility Manager	When primary EOC is not accessible or available and the above options are not the optimal location.

2.3.3.3. In selecting an alternate EOC location, the Utility Manager shall at a minimum consider the following factors:

- Safety of BVES emergency response staff
- Location of hazards and potential movement of hazards
- Location of the emergency
- Communications capability and ability to coordinate efficiently with stakeholders
- Location and accessibility to BVES resources (staff, equipment, material, etc.)

2.4. **Roles and Responsibilities.** This section provides the general intended roles and responsibilities of the BVES Emergency Organization shown in Figure 2-2. It should be noted that the Incident Commander and Group Leaders have the authority to modify roles and responsibilities of those under their responsibility to optimally respond to the specific emergency event. When modifications are made, these should be included during the after action report for the event so that possible changes to the EDRP may be considered. BVES has a small staff, therefore, in the interest of sustainability, efficiency and effectiveness, some staff are "dual hatted" and may be assigned multiple roles and responsibilities.

2.4.1. *Incident Commander*

2.4.1.1. President, BVES is the primary BVES staff assigned. Alternates that may be assigned include: Utility Manager, Energy Resources Manager, Regulatory Affairs Manager, or other BVES officials as directed by the Chief Executive Officer (CEO).

2.4.1.2. Incident Commander reports directly to the CEO.

2.4.1.3. Overall responsible for organizing and directing the EDRP by providing strategic direction for the emergency response. Activities associated with the Incident Commander are mostly strategic in nature and include, but are not limited to:

- Direct EOC activation. Based on the emergency level and the particular situation surrounding the emergency, may direct partial activation of the EOC.
- Authorize de-activation of the EOC (or any partial de-activation).
- Authorize use of alternate EOC location when appropriate.
- Provide timely and accurate updates to Senior BVES management (CEO, CFO, VP Regulatory Affairs, etc.) of emergency response.
- Approve and/or conduct high-level communications with federal, state, county, and/or city officials as well as other utilities and non-governmental organization (NGOs).
- Approve and/or conduct external communications with media and the public.
- Approve regulatory reports for outages, incidents and accidents (GO-95, GO-128 & GO-166). Work closely with Regulatory Affairs at the General Office (GO).
- Approve situation reports that may be requested by external organizations such as California Utility Emergency Association (CUEA), State of California Office of Emergency Services (OES), San Bernardino County OES, City of Big Bear Lake, California Public Utilities Commission (Safety Enforcement Division and Energy Division), local Incident Commander, etc.
- Ensure Operations, Planning, Logistics, and Finance & Administration Groups (SEMS) are properly resourced to respond to emergency.
- Lead periodic update meetings with the BVES SEMS Group Leaders.
- Approve requests for mutual aid.
- Approve use of emergency contracting and procurement provisions.

2.4.2. Public Information Group.

2.4.2.1. Customer Program Specialist is the primary BVES staff assigned to this group. Alternates who may be assigned include: Energy Supply Specialist, Customer Service Supervisor, or others as designated by the Incident Commander. Generally, the Customer Program Specialist and Energy Supply Specialist (or other staff assigned) shall alternate shifts.

2.4.2.2. Public Information reports directly to the Incident Commander on all public information issues and coordinates directly with the leaders of the Operations, Planning, Logistics and Finance & Administration Groups to stay informed on the latest status of the emergency response. Attends BVES SEMS leadership meetings.

2.4.2.3. Public Information facilitates communication with all stakeholder groups, including the news media and provides a variety of public information services during an electric system emergency. Activities associated with Public Information include, but are not limited to:

- Develop public engagement strategy and directs all aspects of public messaging.
- Keep customers, stakeholders, BVES management and employees informed on the status of the emergency response including extent of outages, cause of outages, damage and

casualty assessments, restoration efforts in progress and planned, estimated time to restore service, and updates to the emergency response through widely available communications channels.
- Act as the central point of contact for any external public inquiries.
- Prepare and distribute public information releases for media, website, social media, interactive voice response and two-way text messages, state and local government, and other BVES stakeholders.
- Prepare and distribute responses to media inquiries.
- Coordinate with the General Office and other stakeholder public information officials.
- Work closely with the Incident Commander, public relations contractor and General Office (Regulatory Affairs) on public engagement.
- Work closely with other SEMS Groups to be informed of latest information.
- Provide line crews, customer service and other staff who operate in the field or interact directly with customers with the latest information to be shared with public.
- Coordinate participation in joint press conferences with other stakeholders as needed or directed.
- Organize press conferences as needed or as directed.
- Assist in preparing the Incident Commander and other BVES staff for press conferences and interviews.
- Follow media and social media for discussion of BVES and develop rapid response to dispel erroneous information.
- Update BVES website, social media, local media, interactive voice response and two-way text messages, and other communications platforms as conditions change.
- Activate advertising campaigns with local media when appropriate.

2.4.3. Operations Group. The Operations Group is overall responsible for all of the emergency response actions in the field necessary to safely restore service to customers. As such, this group is made up of customer service, line crews, field operations, engineering and planning, and power generation staff and contractors. The Emergency Manager leads this group.

2.4.3.1. *Emergency Manager*. Utility Manager is the primary BVES staff assigned. Alternates who may be assigned include: Energy Resource Manager, Utility Engineer & Wildfire Mitigation Supervisor and Field Operations Supervisor. The Emergency Manager reports directly to the Incident Commander. Activities associated with the Emergency Manager are partly strategic and partly tactical in nature and include, but are not limited to:

- Ensure public, employee and contractor safety is top priority in all restoration activities.
- Authorize deviations to the EDRP as necessary to safely, efficiently and effectively execute restoration activities.
- Attend BVES SEMS leadership meetings.
- Issue the work schedule and shift rotations for all staff and contractors assigned to the Operations Group.
- Direct the number of Emergency Service Representatives, System Monitors, Damage Assessment Teams, and Line Crews to be assigned per shift.
- Ensure staff and contractors are adequately rotated to allow for rest and safe operations.
- Authorize overtime labor expense as needed.

- Direct all restoration and emergency response activities in the field.
- Keep Incident Commander and Public Information informed of progress.
- Drive to obtain and communicate “estimated time of restoration” (ETR) for outages and update this information as the situation progresses.
- Coordinate with other SEMS Groups.
- Constantly evaluate restoration progress and optimize utilization of available resources to safely, efficiently and effectively restore service.
- Identify and request additional resources when needed and stand-down resources when no longer required.
- Coordinate restoration activities with other external entities (City, County, Fire Department, Sheriff, CHP, Forestry Service, CALTRANS, other utilities, contractors, etc.).
- Assign and dispatch a knowledgeable BVES representative to local government and/or agency Incident Command as needed.
- Ensure outages, incidents, and accidents are properly documented.
- Assist in preparing regulatory reports for outages, incidents, and accidents (GO-95, GO-128 & GO-166).
- Prepare external situation reports as requested.
- Ensure cost recovery records and documentation for restoration work are being maintained as requested by the Finance and Administration Group.
- Review weather forecast and other external information to optimize restoration response.
- Prepare mutual aid inquiries and requests.
- Communicate logistics requirements to complete restoration activities.
- Work collaboratively with other stakeholder organizations and the General Office as applicable on logistics issues.
- Perform other operations activities as directed by the Incident Commander.

2.4.3.2. *Strategic Operations Supervisor (SOS)*. The Field Operations Supervisor, Utility Engineer & Wildfire Mitigation Supervisor, and Customer Service Supervisor are the primary BVES staff assigned. Alternates who may be assigned include: Utility Manager and the Regulatory Compliance Project Engineer. The SOS reports directly to the Emergency Manager. Activities associated with the SOS are mostly tactical in nature and include, but are not limited to:

- Ensure public, employee and contractor safety is top priority in all restoration activities.
- Maintain the “common operational picture” in the EOC. Utilizes the Outage Management System (OMS), Supervisory Control and Data Acquisition (SCADA), CC&B, GIS applications, and other applications to manage information and data in support of restoration efforts.
- Act as the Emergency Manager’s direct representative in the EOC and direct all operations activities to include all dispatch functions while the EOC is activated. For the purpose of this EDRP, the SOS is equivalent to “Dispatch” and the terms may be used interchangeably.
- Function as the central Dispatch during EDRP implementation. Receive, prioritize, dispatch, and resolve all Field Activities (FA’s) and Transmission and Distribution (T&D) system problems reported by other means per BVES priorities identified in the EDRP.
- Direct all restoration and emergency response activities in the field.

- Direct and supervise the Emergency Service Representative(s), System Monitor, Damage Assessment Team(s), Line Crews (BVES, contracted and/or mutual aid), Bear Valley Power Plant Operators, IT Operations Support and Contracted Services (for example, snow removal, vegetation management, etc.) in all aspects of EDRP activities.
- Ensure resources are safely, efficiently and effectively deployed per the EDRP priorities and as directed by the Emergency Manager.
- Recommend to the Emergency Manager whether to increase, maintain, or decrease restoration resources to safely, efficiently, and effectively execute the restoration activities.
- Properly document outages, incidents, and accidents.
- Maintain cost recovery records and documentation of work completed as requested by the Finance Group at the General Office.
- Review weather forecast and other external information to optimize restoration response.
- Develop logistics requirements necessary to complete restoration activities.
- Keep Emergency Manager and Public Information informed of progress.
- Update Situation Report.
- Dispatch the Bear Valley Power Plant (BVPP) as needed. Coordinate any logistics necessary to operate the power plant.
- Ensure accurate and detailed status of T&D switches, equipment and facilities are maintained in the EOC and updated as changes occur.
- Approve field switching orders and direct all field switching operations.
- Mostly operate in the EOC but may go out to the field as needed to personally view issues. When departing the EOC, the SOS should designate a knowledgeable staff member to be in charge of the EOC during his absence. It may be advantageous for the off-going SOS to tour outage sites immediately after shift and provide the SOS a report. Alternatively, it may be advantageous for the on-coming SOS to tour outage sites prior to shift.

2.4.3.3. *Emergency Service Representative (ESR)*. BVES staff who are assigned to this task are the Customer Service Representatives and the Customer Service Specialist. The number of ESR staff assigned per shift shall be directed by the Emergency Manager. Other staff may be requested to augment the ESR Team or to augment certain functions of the ESR Team (for example, EOC staff may be used to call back customers as needed). Additionally, the ESR function or some portions of the ESR function may be transferred to BVES's contracted call center during non-business hours when call volume is low. ESR staff reports directly to the SOS. Activities associated with the ESR Team include, but are not limited to:

- Process incoming customer calls.
- Issue FA's as appropriate.
- Route FA's to EOC dispatch for action.
- Update the Outage Management System as applicable.
- Assist EOC Dispatch in organizing and prioritizing incoming FA's as directed by SOS.
- During extremely high volume periods, alternative procedures may be employed to route FA's more efficiently as directed by the Emergency Manager. For example, the ESRs may be requested to route a periodic CSV file from CC&B of new FA's to EOC Dispatch instead of individual FA's.
- May be assigned to provide first layer of sorting FA's by type (outage, line down, etc.) as directed by the SOS.

- Respond to customer inquiries on system status using latest information from EOC.
- Provide SOS information on customers with "Life Support" and Access and Functional Needs (AFN) customers affected by outages.
- Update IVR and two-way text messages as directed by the SOS.
- Update Customer Care and Billing (CC&B) with results of completed FA's from EOC.
- Call customers to verify power restoration as directed by SOS.
- Normally ESR staff perform assigned duties in the Customer Service area. The Emergency Manager may direct ESR staff to work at another area.

2.4.3.4. *System Monitor*. Staff assigned to this position are directed by the Emergency Manager and are generally selected from the following staff: Energy Analyst, Regulatory Compliance Project Engineer, Wildfire Mitigation & Reliability Engineer, Utility Planner, GIS Specialist, Engineering Technician, Engineering Inspector, Substation Technician, Meter Technician, Field Inspector, Senior Account Analyst, Account Analyst, and Administrative Support Associate. Other staff as deemed qualified by the Emergency Manager may also be assigned. Normally, one System Monitor shall be assigned per shift but additional System Monitors may be assigned to certain shifts when activity is expected to be high. The System Monitor reports directly to the SOS. Activities associated with the System Monitor include, but are not limited to:

- Assist the SOS in maintaining the "common operational picture" in the EOC. Utilizes the Outage Management System (OMS), SCADA, CC&B, GIS applications, and other applications to manage information and data in support of restoration efforts.
- Work closely with Emergency Service Representatives to transfer information.
- Update the Situation Report.
- Assist in receiving, prioritizing, dispatching, and resolving all FA's and T&D system problems reported by other means per BVES priorities identified in the EDRP.
- Take reports from the Line Crews, Damage Assessment Teams and other field assets and communicate this information to appropriate EOC staff.
- Document outages, incidents, and accidents.
- Maintain cost recovery records and documentation of work completed as requested by the Finance and Administration Group.
- Review weather forecast and other external information and provide this information to the SOS and Emergency Manager.
- Maintain status of the BVPP as needed.
- Assist SOS in maintaining an accurate and detailed status of T&D switches, equipment and facilities in the EOC.
- Assist the SOS in execution of responsibilities as directed.
- Perform assigned duties in the EOC.

2.4.3.5. *Damage Assessment Team (DAT)*. Staff assigned to this team are as directed by the Emergency Manager and are generally selected from the following staff: Field Inspector, Substation Technician, Meter Technician, Field Serviceperson, Meter Readers, Wildfire Mitigation & Reliability Engineer, Utility Planner, GIS Specialist, Engineering Technician, Engineering Inspector, Buyer, Storekeeper, Regulatory Compliance Project Engineer, and Energy Analyst. Other staff as deemed qualified by the Emergency Manager may also be assigned to this team. Normally, each DAT shall consist of two people. At least one DAT shall be assigned to each shift. Additional DATs may be assigned to certain shifts when activity is expected to be high. The DAT reports directly to the SOS. Activities associated with the DAT include, but are not limited to:

- Assist the SOS in execution of responsibilities as directed.
- Perform field investigations as directed by SOS.
- Keep the SOS informed of their position when out in the field.
- Provide detailed assessments and documentation including photographs and video of damage to SOS.
- Coordinate with and assist Line Crews as directed by SOS.
- Normally travel in pairs; especially during storm and other potentially hazardous conditions and at night. When conditions are favorable, the Emergency Manager may permit DAT field inspections to be performed by a single person.
- When not in the field, perform duties in the EOC as directed by the SOS.

2.4.3.6. *Line Crews*. Staff assigned to this crew are BVES Journeyman Lineman Crews (including Apprentice employees). Other BVES staff that are Journeyman Lineman (for example, Field Inspector) may be assigned as needed and directed by the Emergency Manager to augment BVES Line Crews. Emergency Manager may also assign Contracted Line Crews and Line Crews from other utilities through mutual aid agreements. The Emergency Manager shall direct the specific crew sizes, shift lengths and rotations, and functions (such as construction, service response, wire down and minor damage response, switching operations, patrols, damage assessments, etc.). The Line Crews report directly to the SOS. Activities associated with the Line Crews include, but are not limited to:

- Perform field activity work (such as construction, service response, wire down and minor damage response, switching operations, patrols, damage assessments, etc.) as directed by SOS.
- Keep SOS informed of work progress and developments in the field.
- Keep SOS informed of the status of T&D switches, equipment and facilities.
- Provide information (such as labor hours, equipment usage, and material consumption) to allow the collection of accurate cost recovery records and documentation for work completed.
- Assist in documenting outage and T&D system damage and restorations efforts.
- Consult with SOS on technical issues that may require Engineering & Planning evaluation and input.
- Request additional resources as needed.
- Operate Bear Valley Power Plant engines as directed.

2.4.3.7. *Engineering Technical Support*. The primary assigned are Engineering and Planning staff (Utility Engineer & Wildfire Mitigation Supervisor, Regulatory Compliance Project Engineer, Utility Planner(s), Wildfire Mitigation & Reliability Engineer, GIS Specialist, Engineering Technician, and Engineering Inspector) as designated by the Emergency Manager. This function may be augmented by mutual aid from other utilities and/or qualified contractors as the Emergency Manager deems necessary. Normally, Engineering Technical Support is an "on-call" function as requested by the SOS. Engineering and Planning staff are generally "dual hatted" and perform other EDRP functions as assigned by the Emergency Manager. When there is a need for Engineering Technical Support, the System Monitor and SOS shall prioritize the specific workload for each Engineering and Planning staff (for example, Utility Planner may be pulled from the DAT to perform planning activities such as loading assessments on pole replacements and then return to DAT duties once the engineering work is completed).

2.4.3.8. *BVPP Operators*. Primary assigned are the BVPP Operators. BVES Journeyman Lineman may also be assigned as directed by the Emergency Manager. Additionally, the Emergency Manager may contract out for additional BVPP Operators, if needed. The Emergency Manager shall direct BVPP Operators and their shift schedule as necessary to support the anticipated or actual dispatching of the power plant. The BVPP Operators report directly to the SOS. Activities associated with the BVPP Operators include, but are not limited to:

- Operate the BVPP as directed by SOS.
- Maintain BVPP at the ready when not dispatched.
- Ensure backup systems fully operational.
- Ensure readiness to perform "Black Start" procedure.
- Request additional resources as needed.
- Document materials and labor hours expended.

2.4.3.9. *IT Operations Support*. Primary assigned is the Senior Technical Operations Support Specialist and the Technical Operations Support Specialist. GSWC IT resources may provide backup support for this function. IT Support shall report directly to the SOS. Activities associated with IT Support include, but are not limited to:

- Ensures utmost business continuity by monitoring and maintaining EOC, Operations & Planning, Customer Service, Accounting and Energy Resources communications and IT systems are operating properly.
- Provides support to ensure connectivity to critical applications.
- Coordinates communications and IT systems issues with GSWC IT.
- Resolves local IT and network connectivity issues with field equipment and systems (for example, SCADA).
- Coordinates communications and connectivity with other entities as directed.
- Assists with other duties as directed by the SOS.

2.4.4. Logistics Group.

2.4.4.1. The Accounting Supervisor is the primary BVES staff assigned in charge of the Logistics Group. Alternates that may be assigned include the Senior Accounting Analyst, Buyer or others as designated by the Incident Commander.

2.4.4.2. The Logistic Group shall normally be made up Accounting Supervisor, Senior Account Analyst, Buyer, Storekeeper, Accounting Analyst, Administrative Support Associate, and other staff as designated by the Incident Commander.

2.4.4.3. Logistics Group reports directly to the Incident Commander on all logistics issues and coordinates directly with the leaders of the Operations, Planning, Logistics and Finance & Administration Groups to provide optimal logistics support to ensure restoration activities are safe, efficient and effective. Activities associated with Logistics Group include, but are not limited to:

- Group leader attends BVES SEMS leadership meetings.
- Maintain at least one group member at the EOC. EOC presence may be modified to “on call” when logistics work is not significant (for example, during night shift) as approved by the Incident Commander.
- Work closely with Emergency Manager and SOS to forecast contracted services, equipment and material requirements for restoration activities.
- Invoke contracts for response services as requested by the Emergency Manager (for example, emergency line work, snow clearing, tree trimming and clearing, etc.).
- Process emergency contracts and procurement requests as needed to support emergency restoration activities.
- Ensure materials for recovery activities are available, issued to Line Crews as needed, and properly documented when utilized or consumed.
- Ensure vehicle fleet fueled, winterized and ready to support response activities.
- Ensure BVES facilities properly functioning to support EOC and response activities.
- Arrange meals as necessary for staff engaged in response activities.
- Arrange lodging and other mobilization logistics for mutual aid and contracted crews as requested by the Emergency Manager.
- Work collaboratively with other stakeholder organizations and the General Office as applicable on logistics issues.
- Perform other logistics activities as directed by the Incident Commander.
- Develop lists of lessons learned for after action evaluation and improvements to logistics.

2.4.5. Planning Group.

2.4.5.1. The Energy Resources Manager is the primary BVES staff assigned in charge of the Planning Group. Alternates that may be assigned include the Utility Manager, Regulatory Affairs Manager, or others as designated by the Incident Commander.

2.4.5.2. The Planning Group shall normally be made up of the Regulatory Affairs Manager, Utility Manager, Customer Care and Operations Support Supervisor, Accounting Supervisor, Energy Supply Specialist, Energy Analyst, and other staff as designated by the Incident Commander.

2.4.5.3. The Planning Group reports directly to the Incident Commander on all planning issues and coordinates directly with the leaders of the Operations, Logistics and Finance & Administration Groups to provide optimal planning support to ensure restoration activities are safe, efficient and effective. Activities associated with Planning Group include, but are not limited to:

- Group leader attends BVES SEMS leadership meetings.

- Maintain at least one group member at the EOC. EOC presence may be modified to "on call" when planning work is not significant (for example, during night shift) as approved by the Incident Commander.
- Work closely with Emergency Manager to develop a high level restoration strategy.
- Evaluate the adequacy of response and recommend adjustments as needed.
- Evaluate weather forecasts and other event information to develop contingencies.
- Determine if Catastrophic Emergency Memorandum Account (CEMA) request is appropriate and coordinate with local government officials and Regulatory Affairs on emergency declarations.
- Develop load forecasts and plan sources of energy supply to best meet load demand.
- Work collaboratively with other stakeholder organizations and the General Office as applicable on planning issues.
- Perform other planning activities as directed by the Incident Commander.
- Develop lists of lessons learned for after action evaluation and improvements to plans.

2.4.6. Finance & Administration Group.

2.4.6.1. The Accounting Supervisor is the primary BVES staff assigned in charge of the Finance and Administration Group. Alternate staff may be assigned include the Energy Resource Manager, Senior Account Analyst, or others as designated by the Incident Commander.

2.4.6.2. The Finance & Administration Group shall normally be made up of the Senior Account Analyst, Account Analyst, Administrative Support Associate, and other staff as designated by the Incident Commander.

2.4.6.3. The Finance & Administration Group reports directly to the Incident Commander on all finance and administration issues and coordinates directly with the leaders of the Operations, Logistics and Planning Groups to provide optimal Finance & Administration support to ensure that restoration activities are safe, efficient and effective. Activities associated with Finance & Administration Group include, but are not limited to:

- Group leader attends BVES SEMS leadership meetings.
- Maintain at least one group member at the EOC. EOC presence may be modified to "on call" when planning work is not significant (for example, during night shift) as approved by the Incident Commander.
- Work closely with Operations & Logistics Groups to track expenses (labor, invoices for services, materials consumed, etc.).
- Ensure clear guidance provided to groups to ensure expenses properly tracked.
- Treat each event as possible Catastrophic Event, which costs could be authorized for recovery.
- Execute CUEA administrative requirements as needed.
- Work collaboratively with other stakeholder organizations and the General Office as applicable on finance and administration issues.
- Perform other finance and administrative activities as directed by the Incident Commander.

- Develop lists of lessons learned for after action evaluation and improvements to finance and administration.

2.5. **Plan Changes.** BVES Incident Commander has the authority to modify this plan including the organizational structure as needed to optimally respond to the specific emergency at hand. Specifically, the Incident Commander, must evaluate each emergency situation and determine:

- To what extent should the BVES Emergency Organization be staffed.
- To what extent should the EOC be activated.
- Should additional resources (for example, mutual aid and/or contracted services) be mobilized.

3. Emergency Response Event Preparations.

3.1. **Preparations.** Emergency Response preparations are a long-term process for which each BVES Department must be constantly ready, especially during the winter months. Preparations for emergency response are best achieved through training on the EDRP, continuous evaluation of the plan, coordination and outreach with external stakeholders, provisioning emergency response materials and equipment, and establishing mechanisms to rapidly bring emergency response resources to the service area such as mutual aid agreements, contracts, and other partnering agreements.

3.2. **Emergency Response Preparations Checklist.** Appendix B, Emergency Response Preparations Checklist, is designed to assist Managers and Supervisors in short-term emergency response preparations.

3.2.1. The President shall direct the execution of the Emergency Response Preparations Checklist based on available forecasting information. In general, it is easier to stand down from a forecasted storm event that does not materialize than to ramp up in the middle of a major storm event. Therefore, erring on the side of being ready is always the better choice. The President may direct the suspension of the Emergency Response Preparations Checklist if the forecast changes and it is no longer warranted.

3.2.2. The checklist is ideally triggered at the 96-hour point prior to a potential emergency response event such as a major forecasted winter storm. However, staff must be flexible and understand not all emergency response events will be accurately forecasted; hence, the implementation time of this checklist may be significantly less than 96-hours. In the event that major outages occur without warning, it is still useful to go through the Emergency Response Preparations Checklist and complete the preparatory checklist items as applicable.

3.2.3. The checklist is designed to be all-inclusive of plausible emergency response to storm events for the BVES service area such as winter snow storms. Therefore, certain preparatory items may not be applicable for all emergency response events; for example, vehicle snow chains may not be required during a loss of import power supply lines from Southern California Edison (SCE). The Utility Manager may direct that certain items on the checklist need not be executed as applicable. Additionally, the Utility Manager may direct new preparatory items be added to the checklist depending on specific impending conditions. The Utility Manager shall use this checklist as applicable when extreme fire threat weather that could result in PSPS conditions is forecasted. The Utility Manager shall keep the President informed of any changes to the checklist.

3.2.4. During after action reviews for emergency response events as well as the annual Emergency Preparedness and Response Plan drill, the Emergency Response Preparations Checklist should be reviewed for adequacy and updated as applicable.

3.3. **Contingency Operating Procedures.** The Field Operations Supervisor shall develop pre-approved switching orders and operating procedures that would most likely to be used in the more plausible loss of supply and outage scenarios. The Field Operations Linemen, the

Power Plant Operators, and other applicable BVES Staff should train on these procedures as applicable so that in the event they are needed, the procedures are readily available, approved, and understood by staff. Switching orders and operating procedures should include at a minimum the following:

- BVPP Black Start System Line-up Switching Order.
- BVPP Black Start Engine Startup Procedures (with and without back-up BVPP generator).
- Switching Order to express the Radford SCE Source to Meadow Substation.
- Rolling blackout procedure when only Radford SCE Source and BVPP are available (13.4 MW Capacity Limit).
- Rolling blackout procedure when only BVPP is available (8.4 MW Capacity Limit).
- Load shedding procedures and priorities.
- Proactive de-energization of high risk circuits in the event of extreme fire threat weather.

3.4. **Mobile Emergency Generation.** The Utility Manager shall ensure that there is a contingency plan to connect mobile emergency generators to the BVES system to provide emergency power. The contingency plan should at a minimum include the following:

- Source at least 5 MWs of mobile emergency generation (may be multiple generators) that may be brought to the BVES service area within 24 hours of being requested. If possible, at least two vendor sources should be identified.
- Identify the fuel requirements and replenishment source(s) for the proposed mobile emergency generation.
- Identify the locations in the BVES system where the mobile emergency generators would be located and connected to the BVES system.
- Identify the connection type and ensure that this is compatible with the sourced mobile emergency generators and the BVES system.
- Identify if any networking is required by the supplier for the mobile emergency generators to operate and, if so, how this shall be accomplished.
- Identify any protection needed and ensure that it is available between the source mobile emergency generators and the BVES system connection points.
- Identify the operating control requirements for the sourced mobile emergency generators (for example, monitoring requirements, startup and shutdown procedures, voltage and load regulation, phase synchronization, operating checks and maintenance, operator labor requirements, etc.) and address how these shall be accomplished (for example, supplier shall operate the mobile emergency generators, etc.).

3.5. **Material and Equipment.** Obtaining material and equipment is always a challenge given that the BVES service area is remotely located and at approximately 7,000 feet in mountainous terrain with only three points of access. The roads present a significant challenge to large trucks under most conditions and all vehicles in wintery ice and snow conditions. Therefore, it is essential to the success of BVES' emergency response plan that certain minimum levels of materials and equipment be always readily available in the BVES service area.

3.5.1. The Utility Manager shall provide the Accounting Supervisor a minimum quantity of T&D equipment and materials to maintain at BVES to allow timely repairs to likely T&D system failures (overhead facilities, underground facilities, and substation equipment). Additionally, the Utility Manager should identify other vital spares to sustain BVPP operations.

3.5.2. The Field Operations Supervisor shall provide the Accounting Supervisor the minimum quantities of materials and supplies necessary to safely operate field crews involved in restoration repairs. These supplies should include items such as traffic control markers and signs, caution cones, portable site lighting, caution lighting, yellow CAUTION tape and red DANGER tape, portable safety barriers, personal protective equipment (PPE), winter and foul weather gear, etc.

3.5.3. All Managers and Supervisors shall ensure that their staff that would be assigned to operate in the field have available to them the appropriate PPE, adequate weather protection (cold weather gear, rain gear, sunscreen and head gear, etc.), and equipment to perform their duties as assigned by the EDRP.

3.5.4. The Buyer and Storekeeper under the supervision of the Accounting Supervisor shall ensure the equipment and materials identified above are stocked to the minimum quantities. Additionally, they shall ensure the identified equipment and materials are readily sourced and may be ordered and delivered in short timeframe.

3.6. **Vehicles.** All Managers and Supervisors are responsible for ensuring that the vehicles and trucks assigned to them and their employees are ready to operate safely and as needed during restoration activities under the anticipated weather and terrain challenges of the BVES services area.

3.6.1. The Accounting Supervisor shall develop a minimum list of equipment for all BVES vehicles to operate safely in the anticipated weather and terrain conditions including snow and ice that are reasonably encountered in the BVES service area (for example, snow tires, snow chains, shovel, first aid kit, light, fire extinguisher, etc.).

3.6.2. The Field Operations Supervisor shall develop a list of any additional equipment necessary for all utility trucks (digger and bucket trucks), work trucks (foreman and Dutyman trucks) and other vehicles used by Field Operations employees to operate safely and as needed in the anticipated weather and terrain conditions that are reasonably encountered in the BVES service area.

3.6.3. The Storekeeper under the direction of the Accounting Supervisor shall coordinate with the applicable Managers and Supervisors to ensure all vehicles and trucks are fully equipped, properly serviced, and ready to safely operate as needed in the anticipated weather and terrain conditions that are reasonably encountered in the BVES service area.

3.6.4. If a vehicle is not properly equipped, in good working order, and/or safe to operate for the current or anticipated conditions, it should be identified as such by the applicable Manager or Supervisor that is responsible for the vehicle or truck and restricted in use (for example, if a vehicle is not equipped with snow tires and chains, it should not be used in snow conditions).

3.7. **Contracts for Services.** During emergency restoration response activities, outside contracted services may be required to ensure efficient and effective restoration of electric service. However, it is extremely difficult to source and contract out services on short notice during an emergency. Therefore, Managers and Supervisors should identify the critical contracted services that may be reasonably expected to be needed for restoration activities, source providers of these services, and establish emergency contract agreements in accordance with the BVES's procurement policy.

3.7.1. **Table 3-1** lists the contracted services that should have pre-arranged emergency contract agreements in place.

Table 3-1: List of Minimum Contingency Contracted Services

Contracted Service	Responsibility	Additional Emergency Requirement
T&D overhead and underground high voltage utility power line construction.	Utility Manager	• Must have 24/7 contact. • Onsite within 8 hours.
T&D substation and major electrical equipment troubleshooting, repair and replacement services.	Utility Manager	• Must have 24/7 contact. • Onsite within 24 hours.
T&D work package design and development services.	Utility Engineer & Wildfire Mitigation Supervisor	• Onsite within 48 hours.
Civil construction for utility underground infrastructure repair and construction, road and sidewalk repair and construction, retaining wall repair and construction, backhoe services, hauling and other civil construction services.	Field Operations Supervisor	• Must have 24/7 contact. • Onsite within 8 hours.
Crane and lifting Services.	Field Operations Supervisor	• Must have 24/7 contact. • Onsite within 8 hours.
Vegetation clearance from high voltage overhead power lines and tree removal.	Field Operations Supervisor	• Must have 24/7 contact. • Onsite within 8 hours.
Airborne inspection, heavy lift and construction services	Utility Manager	• Must have 24/7 contact.
Environmental cleanup and mitigation to oil and hazmat spills.	Accounting Supervisor	• Must have 24/7 contact. • Onsite within 8 hours.
Welding and metal fabrication services.	Field Operations Supervisor	• Must have 24/7 contact. • Onsite within 8 hours.
Snow removal for BVES Main Facility and Stockyard, substations and other areas as directed.	Field Operations Supervisor	• Must have 24/7 contact. • Onsite within 4 hours.
Troubleshooting, repair and replacement parts for emergency generators (Main Office and BVPP).	Field Operations Supervisor	• Must have 24/7 contact. • Onsite within 12 hours.
Mechanical and electrical troubleshooting, repair services and replacement parts for BVPP equipment and support systems (Waukesha Model VHP7104GSI engine/generator sets).	Field Operations Supervisor	• Must have 24/7 contact. • Onsite within 12 hours.
Utility Truck troubleshooting, repair and support services	Field Operations Supervisor	
Vehicle troubleshooting, repair and support services	Storekeeper	
Diagnostic and technical support services for SCADA and associated network systems.	Senior Technical Operations Support Specialist	

Contracted Service	Responsibility	Additional Emergency Requirement
Diagnostic and technical support services for Outage Management System (OMS) and related applications.	Senior Technical Operations Support Specialist	
Diagnostic and technical support services for Interactive Voice Recording (IVR) and related applications.	Customer Service Supervisor	
Diagnostic and technical support services for BVES's phone system.	Senior Technical Operations Support Specialist	
Diagnostic and technical support services for BVES's internal and external network and connectivity systems.	Senior Technical Operations Support Specialist	
Diagnostic and technical support services for BVES's External Website.	Customer Program Specialist	
Public relations (PR) services	Customer Program Specialist	• Must have 24/7 contact. • Provide remote PR response within 2 hours
Media advertising services	Customer Program Specialist	

3.7.2. Many of the services listed in Table 3-1 are used in the normal course of BVES operations through already established contracts. Where this is the case, it is advantageous to include any additional emergency response requirements rather than sourcing to different suppliers.

3.7.3. The Administrative Support Associate in coordination with the Utility Manager and Accounting Supervisor shall develop a list of Contingency Contracted Services and file the list in Appendix C, Contingency Contracted Services. The list shall be in tabular format and at a minimum include the following information:

- Contractor Entity Name
- Services Provided with brief description of any specific emergency requirements
- Point of Contact
- Contact phone numbers including afterhours numbers
- Main Office location

The list shall be reviewed and updated by the Administrative Support Associate each quarter.

3.7.4. Where onsite mobilization is required to perform the requested services, Managers and Supervisors should carefully consider the feasibility for the contractor to reach the BVES service area in a timely manner given the remote and mountainous terrain.

3.7.5. When advanced warning or forecasting is available, the Utility Manager may direct pre-positioning of equipment and materials to improve the ability of the contractor to mobilize. For example, a contractor for T&D overhead and underground high voltage utility power line construction may be requested to pre-position trucks at BVES ahead of a snow storm.

3.7.6. When advanced warning or forecasting is available, it is generally useful for Managers and Supervisors alert their points of contact for contracted services that there may be an impending requirement for their services.

3.8. **Mutual Aid.** Mutual Aid agreements are an efficient and effective resource multiplier available to BVES restoration efforts. Therefore, it is extremely important that these agreements be maintained current and that staff understand what resources they may provide and how to request the resources.

3.8.1. California Utilities Emergency Association. The California Utilities Emergency Association (CUEA) Mutual Aid Agreement allows member utilities to request and obtain labor, materials, and/or equipment resources from other member utilities in a rapid manner on a reimbursable basis. BVES shall be an active member of CUEA and shall participate in the Energy Committee meetings and activities as feasible. Generally, CUEA meetings and activities provide information on emergency response planning at other utilities and state agencies. Additionally, CUEA is an excellent forum for organizations to discuss best practices. The Utility Manager shall be responsible for managing CUEA mutual aid agreement and shall ensure processes are in place and applicable Operations Staff are trained to:

- Inquire about CUEA resources and make formal mutual aid requests in accordance with the CUEA agreement.
- Provide mobilization support such as lodging and meals to responding mutual aid crews and other labor resources provided through CUEA.
- Direct and manage mutual aid crews and other labor resources provided through CUEA.
- Provide logistics support (materials, equipment and other resources as needed) to mutual aid crews and other labor resources provided through CUEA.

The Administrative Support Associate shall ensure CUEA documents are available to the Operations Group and in the EOC.

The Accounting Supervisor shall ensure processes are in place to account for and pay for CUEA mutual aid resources that respond to BVES' aid requests. This shall require close coordination with the Operations Group.

3.8.2. Mountain Mutual Aid Association. The mission of the Big Bear Valley Mountain Mutual Aid Association ("MMAA") is to coordinate and facilitate resources to minimize the impact of disasters and emergencies on people, property, the environment, and the economy. This is accomplished by detailed valley-wide evacuation planning and dedicated support to all involved emergency responders and their agencies. MMAA's vision is to prepare Big Bear Valley citizens, tourists, businesses, and governments to maximize their resistance to disaster through preparedness, mitigation, response, and recovery activities. BVES shall be an active member of MMAA and shall actively participate in the MMAA meetings and activities. This is especially important in establishing strong personal business relationships with key players and stakeholders in the community such that during an emergency event, the BVES Team is working with stakeholders it is already familiar with. **Table 3-2** provides a listing of the MMAA current membership. The Utility Manager shall be responsible for managing MMAA mutual aid agreement and shall ensure processes are in place and applicable Operations Staff are trained to:

- Coordinate activities with MMAA.
- Request support and resources of MMAA members.

MMAA has the ability to provide a wide range of direct support to BVES restoration activities during emergency response including traffic controls, road-clearing services, coordination with local government agencies, other utilities, and other nongovernmental organizations, and communications with the public. Additionally, one of the most significant strengths of MMAA is its ability to coordinate through its member organizations support and relief for customers experiencing extended sustained major power outages. This may include health and welfare checks, shelters, meals, cooling centers, restroom and shower stations, etc.

Table 3-2: Bear Valley Mountain Mutual Aid Association Membership

Organization		
• City of Big Bear Lake • Big Bear Fire Department • San Bernardino County Fire • San Bernardino County Department of Public Health • San Bernardino County Office of Emergency Services (OES) • San Bernardino County Sheriff's Department • San Bernardino County Transportation Authority • San Bernardino County Emergency Communications Service (ECS) • U.S. Forest Service • California Highway Patrol • California Department of Transportation	• Big Bear Airport • Big Bear City Community Services District • Big Bear Lake Department of Water & Power • Big Bear Lake Municipal Water District • Big Bear Area Regional Water Authority • Bear Valley Electric Service, Inc. • Southwest Gas • Bear Valley Community Healthcare District • Bear Valley Unified School District • Mountain Area Regional Transit Authority	• Bear Mountain Ski Resorts • Big Bear Chamber of Commerce • Big Bear Lake Resort Association • Big Bear Valley Recreation & Park District • American Red Cross • Big Bear Community Emergency Response Team (CERT) • Big Bear Valley Community Organizations Active in Disaster (COAD) • Big Bear Valley Voluntary Organizations Active in Disaster (VOAD) • Civil Air Patrol • Salvation Army

3.9. **Communications Layers and Message Deck.** Communications with stakeholders and customers during emergency response is one of BVES' top three priorities. The Customer Service Supervisor with the support of the Customer Program Specialist shall ensure the following:

- Multiple layers of communications are established to reach customers. These should include agreements with local media (newspaper, internet news, radio stations, etc.), BVES Website, BVES social media, Interactive Voice Response (IVR) System, email blast, etc.
- Training applicable staff and testing all of the established communications layers.
- Leveraging the communications platforms available to other stakeholder organizations. For example, the Big Bear Chamber of Commerce has an email blast channel to its member businesses and the City of Big Bear Lake has an email blast channel to many of its residents.
- Developing pre-approved message templates that properly guide staff preparing communications to customers and stakeholders with the necessary information to provide a useful update. For example, pre-staged press releases, website messages, social media messages, IVR messages, etc. on sustained outages may be prepared well in advance of any emergency with "fill-in-the-blanks" for the specific event.

3.10. **Staff Roster and Recall List.** A critical component of successfully implementing the EDRP is the ability to rapidly recall staff as need. Therefore, it is critical that contact information for each staff be maintained up to date and be made available to staff that would execute the recall.

3.10.1. The Administrative Support Associate is responsible for maintaining and updating the BVES Staff Roster and Recall List. This list shall be filed in Appendix D, BVES Staff Roster and Recall List, to the EDRP. This list shall be reviewed for accuracy each quarter by the Administrative Support Associate and updated as needed.

3.10.2. When new staff join or staff terminate their employment at BVES, the Administrative Support Associate shall update BVES Staff Roster and Recall List.

3.10.3. Additionally, when staff change their contact information, it is essential that they inform their Supervisor and the Administrative Support Associate so that the recall roster may be updated.

3.10.4. The recall roster should include at a minimum employee name, home phone, mobile phone, personal email, and address. It is critically important that the roster have a phone number where the employee may be contacted at any time. The address is important because in a major storm it may be safer and more efficient to send a BVES vehicle to pick up staff to respond to the EDRP and staff up the EOC. Personal email is important because an initial group email blast may be sent to set in motion mobilization of the EOC, while calling each staff member is pursued.

3.10.5. The Administrative Support Associate shall develop and update as necessary a group email address for staff using both their personal and work email addresses for recall purposes.

3.11. **Key External Contacts List.** BVES' ability to contact external stakeholders and resource providers is critical to successfully executing EDRP restoration activities.

3.11.1. The Administrative Support Associate in coordination with Managers and Supervisors shall develop the Key External Contacts List and file the list in Appendix E, Key External Contacts List. The list shall be in tabular format and at a minimum include the following information:

- Key External Contact Entity Name
- Point of Contact
- Contact phone numbers including afterhours numbers
- Email
- Main Office location
- Category of Key External Contact per Table 3-3

The list shall be reviewed and updated by the Administrative Support Associate each quarter.

3.11.2. Managers and Supervisors should provide the Administrative Support Associate updates to the Key External Contacts List as changes occur.

3.11.3. Table 3-3 provides the minimum key external contact categories that should be included in the Key External Contacts List.

Table 3-3: Key External Contacts

Category
• State government, agencies and departments
• Local government, agencies and departments
• Critical Customers
• Public Safety Partners
• Utilities
• Non-governmental organizations (business and community organizations; volunteer relief and aid groups; other disaster relief entities)
• Media groups

3.12. **Emergency Operations Center and BVES Main Facility.** Readiness of the EOC and BVES Main Facility to support EDRP restoration activities on short notice is an essential element to successfully executing the EDRP.

3.12.1. The Utility Manager is responsible for ensuring readiness of the EOC as detailed in Section 2.3. Appendix A, EOC Preparedness Checklist, provides a list of equipment, capabilities, materials and supplies that should be available to the primary EOC. The Operations Group should be familiar with this checklist and be trained on setting up the EOC.

3.12.2. Each Manager and Supervisor is responsible for ensuring that facilities and resources under their responsibility are ready to support the EDRP restoration activities.

3.12.3. The Accounting Supervisor is responsible for ensuring the BVES Main Facility is ready to support sustained EOC and EDRP operations to include stocking consumables for EOC and restoration activities, providing staff on-site meals, water and other necessary habitability amenities.

4. Emergency Response Procedures.

4.1. **Emergency Response Plan Implementation and Emergency Operations Center Activation.** BVES responds to emergencies and outages based on the resource requirements to properly resolve the situation in a safe, timely, efficient and effective manner. When the restoration efforts are beyond the capabilities of the normally assigned Field Operations staff and normal Customer Service resources, the EDRP should be implemented.

4.1.1. Response Levels. There are three basic outage response levels that BVES uses. Level 1 and 2 pertain to the EDRP and Level 3 refers the normal BVES working hours and afterhours Field Operations and Customer Service outage response procedures and processes. When the EDRP is activated, Level 1 or 2 are used to describe level of EOC activation and restoration response process. Level 3 is the normal Service Crew (or Dutyman for afterhours) response process to outages and system problems during the course of normal T&D operations. The response levels to outages and emergencies are summarized in Table 4-1.

Table 4-1: BVES Outage and Emergency Response Levels

Response	Event Type	Action	Comments
Level 1	High Risk Long-term*	EOC fully activated EDRP processes implemented	It is preferred to fully activate EOC and then shift to Level 2 activation, if full response determined to not be necessary.
Level 2	Moderate Risk Short-term	EOC partially activated EDRP processes implemented	Level of EOC activation and EDRP implementation as directed by Utility Manager.
Level 3	Low Risk Short-term	Normal Service Crew/Dutyman and Customer Service processes	These events are normally within the capability of assigned Service Crew or Dutyman to resolve with the normal on call resources.

*Long-term is generally defined as 12 hours.

4.1.2. Plan Activation. The President shall direct activation of the EDRP and, therefore, the EOC and shall also direct the applicable response Level. The President should consider the following in evaluating whether or not to implement the EDRP and, if the EDRP is to be implemented, to what Level (1 or 2) to activate the EOC:

- Will resources beyond BVES' normal outage response posture be required and to what extent? Will external resources (mutual aid and/or contracted services be required)?
- Will the restoration efforts be long-term (generally 12 hours or greater)? If long-term, how long?
- Will the restoration efforts be more efficient if the BVES staff is organized for around the clock customer service and field operations?
- Will the restoration efforts require increased management and logistics support beyond that of the Field Operations Supervisor?
- Is the outage (or high potential for outage) expected to have significant impact on BVES customers and/or stakeholders?

- Will rapid and close coordination be required with other government and agencies directing response actions to an emergency (for example, Incident Commander for a wildfire in or adjacent the BVES service area)?
- Will communications efforts require increased and dedicated resources beyond the normal Customer Service communications posture?

4.1.2.1. In considering the above factors, the President shall drive to ensure that the BVES response is at the appropriate level to achieve a safe, timely, and prudent allocation of resources in the best interest of customers and other stakeholders.

4.1.2.2. The EDRP will be directed in response to an extended outage as a result of proactive de-energization (public safety power shutdown) to shut off power in high risk areas when extreme fire conditions present a clear and imminent danger to public safety. The focus of implementing the EDRP in this circumstance would be to improve coordination with local government and agencies and provide affected customers relief resources generally through mutual aid (MMAA) as needed. Specific public safety power shutdown procedures are provided separately in the BVES Public Safety Power Shutdown Plan.

4.1.2.3. The President shall direct activation of the EOC in situations where an outage has not yet occurred but the likelihood is significant. An example of a high risk situation is a wildfire that has not yet resulted in outages but has the potential to do so and/or may require rapid and close coordination with the Fire Incident Commander.

4.1.2.4. It is generally preferred to fully activate EOC and then shift to Level 2 activation as conditions warrant. By bringing in the full EOC organization, the staff can be briefed on the situation and then stood down with specific instructions tailored to the Level 2 response requirements.

4.1.2.5. When the EOC is directed to be activated, the President shall designate staff to utilize Appendix D, BVES Staff Roster and Recall List, to alert employees to staff the EOC. Additionally, a group email should be sent out to staff using their work and personal email address.

4.1.2.6. When the EDRP is implemented for training, such as for the annual drill, the Utility Manager shall put controls in place to prevent drill activities from interfering and/or confusing staff, customers, and stakeholders with real-world BVES operations.

4.2. **Essential Elements of Information (EEI).** EEIs are key information that the Incident Commander and EOC Group Leaders need in order to make timely and informed decisions on emergency response. The EEIs listed in Table 4-2, Essential Elements of Information, are critical to the BVES Emergency Leadership Team's ability to assess the emergency situation and decision making in emergency response. Therefore, obtaining this information and continually updating it must be a priority for all staff assigned to the emergency response efforts.

Table 4-2: Essential Elements of Information

EEI	Remarks
Potential hazards that impact the safety and health of BVES employees, contracted and mutual assistance personnel, first responders, and the public	**Safety is our top priority.** Therefore, it is vitally important to identify potential hazards so that resources may be properly allocated to assessing, mitigating and eliminating the hazards.
Updated common operating picture based on indications and sensors, forecasts, and the accumulation of information from the field	Maintaining a common operating picture is a primary function of the EOC staff so that each Group is able to provide a coordinated and collaborative uniform response to the emergency. Additionally, the common operating picture leads to consistent messaging with customers and stakeholders based on the best available information.

Facility and equipment assessments and operational impacts to BVES' business operations
• Status of Power Delivery Systems
    ○ 34.5 kV sub-transmission system
    ○ Substations
    ○ Distribution system
• Status of Power Supply (**Cause of supply disruptions and estimated time of restoration**)
    ○ SCE Supplies from Goldhill
    ○ SCE Supply from Redlands
    ○ Bear Valley Power Plant
• Status of Communications
    ○ Internet connectivity
    ○ SCADA network
    ○ BVES work radios
    ○ Land line phones
    ○ Cell phones
    ○ Internal network connectivity
    ○ Weather station network
    ○ BVES Website
    ○ BVES Social Media
• Status of IT Applications
    ○ CC&B
    ○ IVR/two-way text
    ○ OMS
    ○ GIS applications
    ○ SCADA
• Status of facilities, equipment, and materials
    ○ Emergency Operations Center
    ○ BVES Main Office
    ○ BVES Yard
    ○ Work trucks and vehicles
    ○ Poles, wire, transformers and other material
	Identifying causes of power delivery system (T&D) outages and supply disruptions is essential to determining the proper restoration actions to be taken.
	
	Maintaining accurate status as conditions in the field change and restoration activities progress throughout the emergency response is key to ensuring restoration resources are properly allocated and optimized at all times.
	
	Developing **estimated time of restoration (ETR)** is critical information that our customers and stakeholders need in order for them plan their responses and mitigations to the outage. ETRs must be updated as they change.
	
	Communications are often the weak link in emergency response. During an emergency some communications may be degraded and alternate systems may be necessary. Therefore, understanding the status of communication systems is critical to ensuring connectivity with field crews, damage assessment teams customers, and stakeholders.
	
	Many utility activities rely upon IT systems for rapid and efficient response. These systems are also susceptible to degradation during an emergency and workarounds may be necessary. Therefore, identifying IT problems and/or limitations is vital to directing effective restoration activities.
	
	As a result of the emergency or for other reasons, facilities and equipment may be degraded and material availability may be limited. Therefore, knowing the status of facilities, equipment, and materials is essential to developing restoration actions.

Status of contracted and mutual aid assistance requests	Outside line crew assistance, tree trimming services, crane support, snow removal services, civil construction services, and other outside assistance is often critical to successfully executing restoration activities. Therefore, is critical to fully understand: • Which entity (or entities) are providing resources? • What specific resources they are providing (equipment and personnel)?

EEI	Remarks
	• How and when will they arrive at BVES's service area? • What logistic support will they require?
Limitations on access and transportation due to flooding, roadway damage, debris, or other closures	Access to BVES's service area under normal circumstances is limited. During an emergency, it is plausible that some or all of the access may be interrupted, which will significantly impact the ability to bring resources to BVES. Additionally, access to certain areas within the service area may be severely impaired due to the emergency. Therefore, it is critical that the EOC Team fully understand access limitations and have backup plans in place.
Interdependencies between BVES, government agencies, other utilities (water, gas, and electric), and critical infrastructure	Outages may have significant impact on government agencies, other utilities (water, gas, and electric), and critical infrastructure; especially, when their backup systems fail. Therefore, the EOC Team must be fully aware of how outages are impacting the area and coordinate a prioritized restoration plan that fully considers the above.
BVES staff supporting other agencies (for example, Incident Commander representative)	Imbedding a BVES representative with the on scene Incident Commander and/or local government EOCs (City or County) has proven to be highly effective in coordinating emergency response actions. The EOC Team must communicate frequently with the imbedded BVES representative to ensure coordinated and uniform emergency response.

4.3. **Restoration Strategy.** Outage events and emergencies are rarely similar in all respects; therefore, this general restoration strategy is constructed to provide the EOC Team with a scalable and flexible restoration strategies that can be employed as required to deal with the unique aspects of each major outage and emergency event.

4.3.1. Restoration Strategy Assumptions. Restoration strategies and guidance in the EDRP assume that the BVES system is in its **normal winter line-up** as follows:

- Bear Valley Power Plant (BVPP) is available for normal full power operations (8.4 MW).
- Goldhill SCE sub-transmission power lines and facilities from Cottonwood (Doble, Cushenberry, Goldhill Switch Station, and Ute 1 & 2) are fully operational and connected to the BVES system at the Shay and Baldwin Auto-Re-closers (34 MW).
- Radford SCE sub-transmission power lines and facilities from Zanja are fully operational and connected to the BVES system at the Radford Auto-Re-closer (5 MW).
- BVES T&D systems are in the normal system line-up.

Therefore, staff must ensure that when implementing guidance provided in the EDRP that they fully understand the current line-up of the BVES system and, if there are deviations to the normal winter line-up, they must properly account for these deviations in their restoration actions. It should be noted that under normal conditions, the Field Operations Supervisor controls the system line-up and during EOC activation the system line-up is controlled by the SOS.

4.3.2. Restoration Priorities. The Utility Manager shall direct the specific restoration priorities keeping safety (public and worker) as the top priority. In most cases, based on best available information regarding the situation and available restoration resources, resources shall be dispatched to restore systems to achieve the following restoration priorities:

- **Public safety** in the affected areas;
- **Worker safety** in performing the restoration work;
- **Critical infrastructure** Sheriff's Department, hospital, Fire Department, key City & County facilities, other utility facilities (water, sewage, gas, communications), Airport, Traffic Control, Incident Commander Site, Incident Base Camp, Incident Evacuation Centers, communications (Spectrum and various cell providers), radio stations;
- Major commercial activities critical to **continuity of community services**: gas stations, food stores, supply stores, repair shops, eateries and lodging facilities to support outside first responders (CAL FIRE), as well as financial institutions.
- **Medical Baseline Customers** and **Access and Functional Needs Customers**
- **Number of customers** affected; and
- **Length of time** customers have been without power;

4.3.3. Restoration Progression. In directing restoration efforts to achieve the priorities of Section 4.2.2 above, the Operations Group shall generally find it most efficient to dedicate restoration resources to restoring the following types of facilities in the prescribed order to optimally restore electric service:

- Energy supply sources Southern California Edison (SCE) supply lines, Bear Valley Power Plant (BVPP), etc.
- Sub-transmission circuits (34.5 kV)
- Substations
- Distribution circuits (4 kV)
- Feeders
- Distribution transformers
- Individual customer service lines

Taking into account restoration priorities and progression, Table 4-3 below provides guidance on the restoration priorities for sub-transmission circuits, substations, and distribution circuits. This guidance must be tempered by many factors including the actual cause of the outage(s), available resources, time to conduct repairs, access to repair sites, etc. Therefore, the Utility Manager must have wide discretion when developing the specific restoration priorities and may choose to deviate from the general guidance.

Table 4-3: Restoration Priorities for Sub-Transmission Circuits, Substations, and Distribution Circuits

Priority	Sub-Transmission Circuit	Substation	Distribution Circuit		Comments
1	Baldwin	Meadow	Garstin		• Key critical infrastructure. • Connects BVPP
2	Shay/Radford	Pineknot Village Maltby Division	Interlaken Boulder Harnish Country Club	Georgia Paradise Erwin Lake Castle Glen	• Additional critical infrastructure • Major commercial activities & airport • Large number of residential customer.
3	NA	Moonridge Maple Bear City Fawnskin Palomino	Eagle Lagonita Fox Farm Clubview Sunset	Goldmine Holcomb Pioneer Sunrise	• Mostly residential customers
4	NA	Bear Mountain Summit Lake	Geronimo Skyline	Lift Pump House	• Mostly interruptible customer.

4.3.4. Loss or Significant Reduction of Energy Supply. BVES normally imports all of the supplies necessary to meet customer demand via SCE power lines and augments the supplies using the BVPP when the maximum capacity from the SCE Cottonwood lines are reached. Table 4-4 provides information on BVES system sources of power.

Table 4-4: BVES System Sources of Power

Source	Capacity	Comments
Goldhill: Includes SCE lines and facilities from Cottonwood (Doble, Cushenberry, Goldhill Switch Station, and Ute 1 & 2).	34 MW	Connected to the BVES system at the Shay and Baldwin Auto-Re-closers
Radford: Includes SCE line (Bear Valley) and facilities from Zanja.	5 MW	Connected to the BVES system at the Radford Auto-Re-closer
Power Plant: Includes Bear Valley Power Plant (BVPP) generation equipment and facilities.	8.4 MW	Seven 1.2 MW natural gas fired engines
Net Energy Metering & Distributed Energy Resources	3.3 MW	Distributed throughout system. Limited to day-light production only

Table 4-5 provides guidance on some of the more likely loss of energy supply scenarios to the BVES Service Area. Each of these scenarios assumes a complete loss of the affected power source(s). However, it should be realized that it is also possible that certain power sources may be degraded providing some limited capacity instead of being completely lost. In these cases, the Operations Group should follow the framework provided in Table 4-5 modified to take into account the limited supply capacity of the degraded power source(s).

Table 4-5: Actions for Loss of Supplies

Actions	Loss of all SCE Supplies (Goldhill & Radford)	Loss of SCE Goldhill Supplies	Loss of SCE Radford Supply	Loss of BVPP
Contact and coordinate with SCE.	Call SCE Lugo Substation and SCE Control Center Colton. Obtain system status, actions in progress or scheduled and	Call SCE Lugo Substation. Obtain system status, actions in progress or scheduled and ETR.	Call SCE Control Center Colton. Obtain system status, actions in progress or scheduled and ETR.	NA

Actions	Loss of all SCE Supplies (Goldhill & Radford)	Loss of SCE Goldhill Supplies	Loss of SCE Radford Supply	Loss of BVPP
	estimated time of restoration (ETR).			
Assess situation	Based on ETR for all or partial energy supplies and demand, take all or some of the actions specified below as appropriate.	Based on ETR for all or partial energy supplies and demand, take all or some of the actions specified below as appropriate.	If situation is long-term, work with interruptible customers to coordinate timing of their loads to reduce or eliminate interruptions.	If situation is long-term, work with interruptible customers to coordinate timing of their loads to reduce or eliminate interruptions.
Activate EOC	Yes – Level 1 Event	Yes – Level 2 Event	No – Level 3 Event	No – Level 3 Event
Switching Operations	Line-up system for BVPP Black Start Procedures	Express Radford to Meadow.	Shift Village Substation to Shay Line	NA
Dispatch BVPP	Execute BVPP Black Start Procedures and Start up Enginators one at a time being careful to not exceed the load capacity.	Start up Enginators one at a time being careful to not exceed the load capacity.	Start up Enginators as needed based on load.	Conduct actions to repair BVPP.
Interrupt interruptible customers	Will be required to meet demand.	Will be required to meet demand.	Possibly required to meet demand. Work with customers to coordinate demand to reduce or eliminate interruptions.	Possibly required to meet demand. Work with customers to coordinate demand to reduce or eliminate interruptions.
Rolling blackout procedures	Will be required to meet demand.	Will be required to meet demand.	Not likely required.	Not likely required.
Contract emergency mobile generation	Consider based on ETR if greater than 24 hours.	Consider based on ETR if greater than 24 hours.	Not likely required.	Not likely required.
Public Engagement	Work with community and stakeholder to reduce non-essential loads. Keep customers and stakeholders informed of ETR and rolling blackouts.	Work with community and stakeholder to reduce non-essential loads. Keep customers and stakeholders informed of ETR and rolling blackouts.	Not likely required.	Not likely required.
Compliance reporting	Conduct CPUC Major Outage Report per GO-166 due to greater than 50% of customers experiencing outage.	Conduct CPUC Major Outage Report per GO-166 due to greater than 50% of customers experiencing outage.	Conduct CPUC Major Outage Report per GO-166 if media coverage expected or occurs.	Not likely required.
Load forecasting	Energy Resources to provide detailed hourly forecasts and make recommendations to support load with BVPP and mobile generation.	Energy Resources to provide detailed hourly forecasts and make recommendations to support load with BVPP and mobile generation.	Energy Resources to provide detailed hourly forecasts and make recommendations to support load without Radford Line.	Energy Resources to provide detailed hourly forecasts and make recommendations to support load without BVPP.

4.3.5. Downed Wire Response. During a major storm, BVES may receive many trouble calls reporting primary and service lines down throughout the service area. Wires down that present an imminent fire or electrocution hazard or are identified as being primary distribution line voltage shall receive top priority. In general, higher priority shall be assigned to calls involving wires blocking state highways or wires down on buildings or vehicles. Personnel investigating downed wire shall determine the wire type (primary, secondary or service conductor) and take actions as directed by the SOS and per Table 4-6, Downed Wire Response.

Table 4-6: Downed Wire Response

Conductor	Action
Primary	

Conductor	Action
	• If a fire has started or the threat of fire is imminent, call 911 and then call the SOS to have the circuit de-energized by the most rapid means possible (this may require dropping the main BVES supply transmission lines remotely). • Warn others to stay clear. • Isolate the area by setting up CAUTION tape and traffic cones and barriers. • Call into the EOC the exact location (address and pole numbers). • If wire is energized, but not a fire threat stay at site until Lineman Crew takes over or the line is de-energized. • Once line is de-energized, area isolated and/or Lineman Crew onsite, proceed to next location as directed by SOS.
Secondary	• If a fire has started or the threat of fire is imminent, call 911 and then call the SOS to have the circuit de-energized by the most rapid means possible. • Warn others to stay clear. • Isolate the area by setting up CAUTION tape and traffic cones and barriers. • Call into the EOC the exact location (address and pole numbers). • If wire is energized and located near a school, high pedestrian area, on a main roadway, or near a conductive structure, but not a fire threat stay at site until Lineman Crew takes over or the line is de-energized. • Once line is de-energized or it is determined that the area is low risk and the area isolated and/or Lineman Crew onsite, proceed to next location as directed by SOS.
Service	• If a fire has started or the threat of fire is imminent, call 911 and then call the SOS to have the circuit de-energized by the most rapid means possible. • Warn others to stay clear. • Isolate the area by setting up CAUTION tape and traffic cones and barriers. • Call into the EOC the exact location (address and pole numbers). • If wire is energized and located near a school, high pedestrian area, on a main roadway, or near a conductive structure, but not a fire threat stay at site until Lineman Crew takes over or the line is de-energized. • Once line is de-energized or it is determined that the area is low risk and the area isolated and/or Lineman Crew onsite, proceed to next location as directed by SOS. • If the line is disconnected from the pole, it is not necessary to isolate the area. Simply call the situation into the EOC and proceed to next location as directed by SOS.

4.3.6. Sub-Transmission and Distribution (T&D) Casualties. The most common cause of outages for the BVES services area are casualties to T&D facilities resulting in a major outage, multiple outages of varying sizes, and/or some combination thereof. Restoration from these outages is mostly dependent on the available resources, which can quickly be overwhelmed if not properly managed.

4.3.6.1. The Operations Group shall prioritize restoration activities and resource allocation according to the general priorities identified in Section 4.3.2 and shall restore T&D facilities in the order listed in Section 4.3.3 to achieve these priorities. In establishing restoration priorities, public and worker safety is always the top priority.

4.3.6.2. SOS balances efforts to conduct repairs while attempting to restore service to as many customers as possible by isolating the damaged facilities to as close to the damage as feasible with the goal of minimizing the number of customers affected by the outage. The SOS should evaluate the time to isolate the damage and restore service to some customers against the estimated time to repair the damage and restore power to all customers. The most efficient and effective course of action shall depend on the extent of damage, availability of resources to conduct repairs, and availability of resources to perform switching operations.

4.3.6.3. Once damaged facilities are identified to the Operations Group, the SOS shall have the facilities field checked by the Damage Assessment Team (DAT) or by other competent staff, such as nearby field crews, to determine the extent of required repairs needed as well as the ability to isolate the damage and restore power to as many customers as possible.

4.3.6.4. Based on the results of the field check, the SOS shall:

- Determine the priority to repair the damages;
- Direct switching operations to restore power to as many customers as possible, if feasible;
- Determine the repair work scope (for example, temporary repair such as shoring up damaged facilities or permanent repair per BVES construction standards, etc.);
- Assign Engineering Planning resources as deemed necessary (for example, perform pole loading assessments for pole replacements);
- Schedule Field Crew resources as applicable;
- Direct assigned Field Crew to draw necessary materials and conduct repairs;
- Inform and periodically update the Public Information Group and Emergency Service Representatives so that they may keep customers and stakeholders informed; and
- Close out or cause to be closed out the applicable Field Activity.

4.4. **EOC and Emergency Response Workflows.** The EOC and emergency response workflows are designed to:

- Develop and maintain an accurate common operational picture.
- Continually assess damage and develop optimal restoration response.
- Dispatch resources for emergency restoration activities.
- Manage field activity reports.
- Keep customers and other stakeholders informed.
- Ensure restoration activities are properly resourced.

4.4.1. EOC Setup. The EOC shall be set up in accordance with Appendix A, EOC Preparedness and Setup Checklist. The Strategic Operations Supervisor in consultation with the Emergency Manager shall direct which applications are to be displayed on the available large screens and projector and how the white board shall be utilized. The displays should be optimized to provide EOC staff and decision makers an accurate common operational picture based on the best information available.

4.4.2. EOC Staffing. The following staff shall normally be present or represented as applicable in the EOC:

- Incident Commander
- Public Information Group
- Emergency Manager
- Strategic Operations Supervisor (SOS)
- System Monitor
- Damage Assessment Team (DAT) – when not assigned to the field

- Emergency Service Representative (ESR) – normally located in the Customer Service area to reduce noise level in EOC
- Engineering Technical Support
- IT Operations Support – normally located in IT spaces
- Logistics Group
- Planning Group
- Finance & Administration Group

4.4.3. Managing Field Activities. The Emergency Manager may find it useful to manage Field Activities by utilizing a spreadsheet to track each Field Activity by recording and sorting the following information:

- Field Activity Number
- Date
- Time
- Location
- Circuit
- Substation
- Status (Unassigned/Crew Assigned/Completed)
- ETR
- Grouping (often multiple Field Activities are resolved when a common fault/damage location is repaired)
- Customer call back
- Comments
- Other information as deemed necessary by the Emergency Manager

4.4.4. Workflows. The EOC shall process incoming damage reports and service request as Field Activities using the workflows shown in Appendix F, Emergency Response Workflows. The emergency response workflows are provided for Level 1 and 2 activations. For reference, the Level 3 (normal service response) is also provided. The Utility Manager may direct deviations to the workflows if it is determined that a more effective and efficient workflow process may be achieved. When conducting after action reviews for emergency response events as well as the annual Emergency Preparedness and Response Plan drill, the Appendix F, Emergency Response Workflows, should be evaluated for possible changes and improvements, and updated if deemed appropriate.

4.4.5. Situation Report. Developing a common operational picture is an important function of the EOC staff in order to ensure decision making is optimal. One essential tool in developing the common operational picture is to periodically update a Situation Report (SITREP). Appendix G provides an example SITREP. The SITREP should be updated by the SOS at least once per shift and more often if conditions are rapidly changing. The SITREP should be displayed in the EOC and sent to the Incident Commander, Public Information Group, EOC Group Leaders, Emergency Service Representatives, and others as deemed appropriate by the Emergency Manager.

4.4.6. Damage Assessments. The Damage Assessment Team(s) shall be dispatched from the EOC to investigate Field Activities and other damage reports. They shall complete a Damage Assessment form and provide it to the SOS. Appendix H provides a sample Damage Assessment Form. If they have several sites to visit, they may consider taking a picture of the completed form and sending to the EOC. Also, the DAT should take as many pictures needed to identify the damage and allow for the Engineering Team to plan the necessary repair work for the line crews. For example, the DAT should take pictures of any damaged equipment and facilities so that material may be pulled and staged for the line crews. Also, the DAT may make use of tools such as FaceTime to communicate with the EOC and provide the EOC a complete assessment of the damage conditions and the iRestore First Responder app to quickly make a basic report with location and a picture.

4.4.7. Work Orders. The SOS shall direct the use of Work Order jackets for the more complex repairs so that the scope of work performed and material and equipment utilized is properly documented. These Work Order jackets should include one-line diagrams and material sheets as applicable along with specific instructions from Engineering & Planning if warranted. Appendix I provides a sample Work Order Jacket.

4.5. **Resources.** Using best available information, the Utility Manager shall continually assess the following:

- Resources necessary to execute the restoration activities in a safe, effective and efficient manner;
- Available resources in the Service Area;
- Gaps in resource availability to execute the restoration activities in a safe, effective and efficient manner; and
- When resources from outside entities such as CUEA mutual aid and/or contracted resources may be released.

Based on the above assessments, the Utility Manager shall coordinate with the Logistics Group leader to request additional resources as necessary to fill resource gaps and to relinquish resources when no longer required. Possible resources in addition to BVES resources include CUEA mutual assistance, contracted services and Big Bear Valley Mountain Mutual Aid Association.

4.5.1. California Utilities Emergency Association (CUEA). The Utility Manager shall determine if gapped resources are best provided by utilizing the hCUEA Mutual Aid Agreement, which allows member utilities to request and obtain labor, materials, and/or equipment resources from other member utilities in a rapid manner on a reimbursable basis. The specific process for requesting and receiving mutual aid from member utilities is provided in the CUEA Mutual Aid Agreement. Table 4-7, CUEA Mutual Assistance Process, provides a summary of the process for requesting and receiving CUEA mutual assistance.

Table 4-7: CUEA Mutual Assistance Process

Process Step	Responsibility	Amplifying Comments
Determine if CUEA Mutual Aid **may** be required	Utility Manager	The Operations Group evaluates if CUEA resources may be required and if there is a possibility, this should be communicated to the Logistics Group.
Issue a "Mutual Assistance Inquiry Only"	Logistics Group Leader	Providing the CUEA Staff with a Mutual Assistance Inquiry Only allows the CUEA to alert member utilities so that they may evaluate which resources are available without incurring costs. This request is best made via email but it may also be made via phone call. The following information should be included in the inquiry: • BVES Contact Name • BVES Contact Phone Number • BVES Contact Email • Type of Emergency • Type of Assistance Requested • Desired Date & Time Needed • Additional Details or Comments
Determine that CUEA Mutual Aid **is** required.	Utility Manager	Obtain Incident Commander's authorization to proceed with CUEA mutual aid request and then, request Logistics Group make arrangements.
Issue a "Mutual Assistance Formal Request"	Logistics Group Leader	Send the CUEA Staff a Mutual Assistance Formal Request with following information: • BVES Contact Name • BVES Contact Phone Number • BVES Contact Email • Type of Emergency • Type of Assistance Requested • Desired Date & Time Needed • Additional Details or Comments This request is best made via email but it may also be made via phone call and then followed up by email.
Pre-arrival coordination	Logistics Group Leader	Once a member utility (referred to as "Assisting Party") agrees to provide resources, the Logistics Group shall work with the Assisting Party point of contact to facilitate all logistics arrangements to include mobilization through demobilization. Specifically, the following information should be obtained: • Date and estimated time of arrival of the Assisting Party resources • Name and contact information of the Assisting Party's Team leader • Names and contact information of the Assisting Party Team members • How lodging will be handled [1] • How meals will be handled [2]
Mutual Assistance Agreement Letter	Finance & Administration Group Leader	Once the pre-arrival information is verbally agreed upon, the Finance & Administration Group shall draft the Mutual Assistance Agreement Letter, route it to the Utility Manager and Logistics Group Leader for review and to the Incident Commander for approval signature. Appendix G, Mutual Assistance Agreement Letter, provides a sample letter.

Process Step	**Responsibility**	**Amplifying Comments**
Setup Assisting Party in BVES Accounts Payable System	Finance & Administration Group Leader	Coordinate with the Assisting Party to ensure they are able to invoice BVES in accordance with the CUEA Mutual Aid Agreement. Provide the Assisting Party invoicing instructions to ensure timely payments.
Mobilization	Logistics Group Leader	Coordinate with Assisting Party Team Leader and local facilities to ensure lodging is ready and assist in resolving any arrival issues such as providing information on access to Big Bear Lake, chain requirements and any other travel support (such as permission to pass through areas that may be closed to general public).
Arrival Meeting	Utility Manager and Logistic Group Leader	Upon arrival of the Assisting Party, the Utility Manager and Logistic Group Leader shall meet with the Assisting Party Team Leader, introduce key staff, and go over the following: • Safety procedures[3] • Coordination meetings[4] • Communications[5] • Work controls and construction standards[6] • Material usage[7] • Situation update[8]
Tour of Facilities	Utility Manager	Following the Arrival Meeting, the Utility Manager shall have a BVES employee provide the Assisting Party with a brief orientation tour of key facilities essential to supporting their work including the following: • EOC • Warehouse • Stockyard • Where to park trucks • Material disposal • Hazmat disposal • Other logistics support (for example, where to fuel trucks)
Demobilization and Departure Out Brief	Utility Manager and Logistic Group Leader	Ensure lodging checkout is completed and bills are paid. Copy receipts. Review material used by Assisting Party and resolve any documentation issues. Discuss any lessons learned or areas for improvement to allow the Assisting Party to be more effective in the future.
Compensation	Utility Manager and Accounting Supervisor	Coordinate with Assisting Party to review invoices in accordance with the CUEA Mutual Aid Agreement with all of the supporting documentation. The Utility Manager should be the approving manager for the invoices.

Notes:
[1]It is BVES's responsibility to make lodging arrangements; however, an Assisting Party may desire to make lodging arrangements on their own and be reimbursed per the Mutual Aid Agreement.
[2]It is BVES's responsibility to provide meals; however, an Assisting Party may desire to make meal arrangements on their own and be reimbursed per the Mutual Aid Agreement.
[3]Review BVES safety procedures to include tailboard policy and documentation, grounding policy, lock-out/tag-out policy, confined space policy and the BVES Accident Prevention Manual.
[4]Agree upon how the Assisting Party shall interact and receive direction on work from the Operations Group. Sometimes it might be efficient for the Assisting Party to have the Team Leader spend time in the EOC with the Operations Group and out in the field with the Assisting Party crews. Other options include having the Crew Forman check-in before and after each shift.
[5]Establish lines of communications with the Assisting Party Team Leader and crews. They may include cell phones and/or BVES provided radios.
[6]Brief the Assisting Party on BVES work controls including how work will be directed and construction standards used by BVES. Ensure Assisting Party understands what they are permitted to do and when they must seek Engineering approval for any deviations.
[7]Brief the Assisting Party on BVES material control and documentation procedures. Also, agree upon how to replenish truck stock.

Process Step	Responsibility	Amplifying Comments

[8]Brief the Assisting Party on the current situation, damage assessments and services that the Assisting Party shall be required to perform. This is an excellent opportunity to develop an initial game plan with the Assisting Party.

4.5.2. Contracted Services. Contracted Services as listed in Table 3-1 should be in place such they may be readily requested. The Utility Manager shall determine which contracted services are needed and the specific scope of work and provide this information to the Logistics Group Leader. The Logistics Group Leader shall contact the requested contracts and make the arrangements to receive the services. Appendix C, Contingency Contracted Services, provides contact information for anticipated contract services.

4.5.2.1. The Logistics Group shall work with the contractor(s) to establish the specific estimated time of arrival, mobilization and demobilization support needed, and the onsite contractor supervisor/foreman contact information.

4.5.2.2. Upon arrival of contracted crews, the Utility Manager, Field Operations Supervisor, and Logistic Group Leader shall meet with the contractor supervisor, introduce key staff, and go over the following:

- **Safety procedures:** Review BVES safety procedures to include tailboard policy and documentation, grounding policy, lock-out/tag-out policy, confined space policy and the BVES Accident Prevention Manual.
- **Coordination meetings:** Agree upon how the contractor shall interact and receive direction on work from the Operations Group. Sometimes it might be efficient for the contractor to have the supervisor spend time in the EOC with the Operations Group and out in the field with the contractor crews. Other options include having the Crew Forman check-in before and after each shift.
- **Communications:** Establish lines of communication with the Assisting Party Team Leader and crews. They may include cell phones and/or BVES provided radios.
- **Work controls and construction standards:** Brief the contractor on BVES work controls including how work shall be directed and construction standards used by BVES. Ensure contractor understands what they are permitted to do and when they must seek Engineering approval for any deviations.
- **Material usage:** Brief the Assisting Party on BVES material control and documentation procedures. Also, agree upon how to replenish truck stock.
- **Situation update:** Brief the contractor on the current situation, damage assessments and services that the contractor shall be required to perform. This is an excellent opportunity to develop an initial game plan with the contractor.

4.5.2.3. Following the Arrival Meeting, the Utility Manager shall have a BVES employee provide the contractor with a brief orientation tour of key facilities essential to supporting their work including the following:

- EOC
- Warehouse
- Stockyard
- Where to park trucks

- Material disposal
- Hazmat disposal
- Other logistics support (for example, where to fuel trucks)

4.5.2.4. Once the Utility Manager releases the contractor from providing further services, an out brief meeting shall be conducted with the contractor supervisor, Utility Manager and the Logistics Group Leader to ensure the following: lodging checkout is completed and bills are paid (if BVES handled mobilization); review material used by contractor and resolve any documentation issues; and discuss any lessons learned or areas for improvement to allow the contractor to be more effective in the future.

4.5.2.5. If a contract is not in place for contracted services that are determined to be necessary for emergency response actions, the Utility Manager may direct, with the President's prior approval, that emergency contracting procedures per the BVES's procurement policy be executed to the obtain the required services. Any verbal service requests should be followed up as soon as feasible in writing (normally by email) by the Logistics Group with the applicable contractor. The email should include the scope of work and price. This should then be followed up with the appropriate procurement documents (for example, contract, service purchase order, etc.).

4.5.3. Big Bear Valley Mountain Mutual Aid Association ("MMAA"). While MMAA does not have power line construction and repair resources, they do have access to significant support resources including traffic controls, road clearing services, coordination with local government agencies, other utilities, and other nongovernmental organizations, and communications with the public. Additionally, one of the most significant strengths of MMAA is its ability to coordinate through its member organizations support and relief for customers experiencing extended sustained major power outages. This may include health and welfare checks, shelters, meals, cooling centers, restroom and shower stations, etc. Therefore, when the Utility Manager determines that some of these resources are needed, he/she shall inform the Logistics Group Leader who shall coordinate with MMAA in accordance with the MMAA Agreement to request and obtain the desired resources. Coordination with MMAA supplied resources should include Point of Contact, resource estimated time of arrival, appropriate briefings and facility tours by the Operations Group (use the guidance in Section 4.3.1), and agreement on reimbursement if applicable.

4.6. **Catastrophic Events Memorandum Account (CEMA).** CEMA is a process to establish an account to allow utilities to recover the incremental costs incurred to repair, restore or replace facilities damaged during a disaster declared by the appropriate federal or state authorities. If a catastrophic event is declared a state of emergency by the state or federal government, then utilities can record costs caused by the event in this memorandum account. It should be noted that the utility cannot record or request recovery of costs incurred before the date the event is declared a state of emergency. By recording these costs, the utilities can later ask for recovery of these costs from the Commission. The CPUC then reviews these costs and approves them as appropriate.

4.6.1. Anytime the EDRP is activated, accurate records of expenses, labor hours, materials and other costs incurred during the recovery from the disaster shall be maintained such that the incremental costs of recovery efforts may be documented in the event CEMA is invoked. The Finance and Administration Group shall provide specific guidance to Staff to ensure accurate records are maintained. Note that often a state of emergency is declared after the event and recovery have transpired, so each EDRP activation should be treated as a CEMA event.

4.6.2. The President shall coordinate with the Regulatory Affairs Manager to ensure that after a state of emergency occurs and BVES begins booking costs resulting from the event, that a letter is sent to the CPUC Executive President within 30 days. The letter shall provide not only the details of the disaster but also an estimate of the costs to be incurred. The Finance and Administration Group shall develop the estimate for the letter with input from the Operations Group.

4.6.3. Regulatory Affairs Manager shall request cost recovery of the CEMA in a formal proceeding. The Utility Manager with assistance from Accounting Supervisor shall provide the necessary details to support Regulatory Affairs in the CEMA filing.

4.7. **Evacuation.** In the event public officials declare an evacuation order, for all or parts of the Big Bear Valley area, staff's first priority is to address the immediate needs and safety of themselves and family, and once that is taken care of then each employee has a role to play as follows.

4.7.1. <u>Critical Workers</u>**.** Certain staff are considered Critical Workers and are issued an Emergency Pass by the San Bernardino County Sheriff's Department. The Emergency Pass is only to be used for BVES work and in accordance with local authority instructions. The Emergency Pass should never be used for personal reasons. BVES Critical Workers are:

- President
- Utility Manager
- Field Operations Supervisor
- Utility Engineer & Wildfire Mitigation Engineer
- Senior Technical Operations Support Specialist
- All Linemen
- Field Inspector
- Substation Technician
- Meter Technician
- Power Plant Operators
- Other staff as designated by the Utility Manager

Every two years the Administrative Support Associate shall request new Emergency Passes for the BVES staff classified as critical workers. Also, when new staff arrive the Administrative Support Associate shall obtain an Emergency Pass for them if they are classified as critical workers.

4.7.2. <u>Evacuation Order</u>. In the event government authorities declare an evacuation order for the Bear Valley area, all staff shall follow the evacuation procedure. For partial evacuation orders, the Utility Manager shall evaluate the extent and impact of the partial evacuation and determine if this procedure should be executed and if modifications to the procedure are warranted. For example, an evacuation order for Fawnskin only would likely result in BVES implementing its EDRP and staffing its EOC, the evacuation procedures would likely not need to be executed.

4.7.2.1. *Utility Manager* shall:

- Direct all non-evacuated staff actions.
- Implement the EDRP.
- Consult the local government Incident Commander (IC) and/or applicable Emergency Operations Center (City of Big Bear Lake or San Bernardino County OES) and determine the desired condition of the distribution system and any support needed.
- Place the distribution system in a safe condition while supporting as practicable the IC's efforts.
- Determine the necessary support staff required to safely operate the system and in consultation with the local government IC where they should be located. If the local government IC determines support staff may safely be located at the BVES Main Office, then that is preferred. If it is not safe to remain at the BVES Main Office, the BVES support staff shall relocate to the Base Camp being utilized by the IC or other designated area as agreed upon by the IC.
- Inform the President of the plan.
- Provide instructions to Critical Workers.
- Release any staff who are no longer needed and direct them to safely evacuate.
- When the evacuation order is lifted, direct restoration activities as needed and the return to normal operations.

4.7.2.2. *Staff classified as Critical Workers* shall:

- Report to the designated area as directed by the Utility Manager. Support staff relocating to the Base Camp or other designated area shall bring utility trucks and equipment as determined necessary by the Utility Manager.
- Dispatch to perform tasks as directed by the Operations Group. BVES staff dispatched to perform tasks in the evacuated areas shall always perform these tasks in at least pairs and shall conduct a communications and status check with the Operations Group at least hourly.
- BVES Staff representative should be assigned to the IC's Base Camp to coordinate any support needed. BVES Representative assigned to the local government IC Base Camp or an EOC shall be designated by the Utility Manager, knowledgeable of the BVES distribution system, and have direct access to the Utility Manager such that IC and/or EOC requests are not delayed.
- Consideration shall also be given to providing BVES Staff representative to supporting Emergency Operations Center (City of Big Bear Lake or San Bernardino County OES).
- Released critical workers in the affected areas should evacuate in a safe manner off the mountain in a safe and orderly manner following local authority instructions. Report to the General Office in San Dimas, CA or other area as designated by the Energy Resources Manager.

4.7.2.3. *Non Critical Worker Staff* in the affected areas should evacuate in a safe manner off the mountain in a safe and orderly manner following local authority instructions. Report to the General Office in San Dimas, CA or other area as designated by the Energy Resources Manager.

4.7.2.4. *Energy Resources Manager* shall:

- Direct all evacuated staff actions.
- If the General Office is not to be used as the evacuation point, designate a suitable area for evacuated staff to gather.
- Perform an accounting of the whereabouts of all BVES staff. Inform the President.
- Setup remote support EOC and establish the Planning, Logistics, and Finance & Administration Groups with available staff.
- Establish continuous and reliable communication lines with Operations Group remaining in the service area.
- Provide resources as requested by the Operations Group.
- Provide updates to President, Regulatory Affairs, and Senior GSWC Staff.
- Make preparations to obtain utility mutual assistance via the California Utilities Emergency Association (CUEA) and/or contracted Linemen as determined necessary by the Operations Group.
- When the evacuation order is lifted, coordinate with the President and Utility Manager the orderly and safe return of staff to the service area.

4.7.2.5. *Customer Supervisor* shall:

- Establish remote customer service support.
- Update public information media as applicable (press releases, website and social media updates, IVR messages, etc.).

4.8. **End State.** The Utility Manager shall direct the transition from emergency response operations under this plan (Level 1 or 2) to normal operations (Level 3) when the following conditions are met:

- BVES system is no longer at risk for continued disruptions due to the incident.
- BVES power supplies are have been restored to meet service area load demand and are evaluated as reliable.
- BVES sub-transmission system is restored to meet service area power delivery needs and is evaluated as reliable.
- BVES substations and distribution systems are restored to meet service area power delivery needs and are evaluated as reliable.
- Response crews have been demobilized.
- System issues and problems are within the normal Level 3 response capabilities.
- Long-term customer support has been established as necessary (for example, following a declaration of a state of emergency because a disaster has either resulted in the loss or

disruption of the delivery or receipt of utility service and/or resulted in the degradation of the quality of utility service) and is capable of being properly managed by the normal supervisory element.

Generally, the transition from Level 1 shall be progressive to Level 2 as emergency response requirements wind down and then to Level 3.

4.9. **After Action Reports.** Once the incident is officially terminated, the Utility Manager shall schedule and conduct formal hot washes/debriefing sessions with applicable staff and have an After Action Report prepared. The After Action Report should include:

- Dates/times of the incident
- Description of the incident
- Level of plan activation and if the EOC was staffed
- Records of public communications that were performed
- List of damages to system
- List of personal deaths, injuries, and other accidents associated with the incident
- List of external (contracted and mutual aid) resources utilized
- Develop incremental cost of emergency response actions
- Lessons learned
- Evaluation on whether or not the plan was properly followed
- Specific improvement actions including assignment of responsibility to complete and due date

A thorough follow-up includes reviewing all plans and procedures, making the necessary revisions from lessons learned, and ensuring distribution to all stakeholders/plan holders.

4.10. **Annual Emergency Response Plan Training and Exercise.**

4.10.1. Annual Training. The Utility Manager shall conduct staff training for designated personnel on the Emergency Response Plan in preparation for emergencies and major outages each year just before the winter storm season; typically, in September or October. The training shall be designed to overcome problems identified in the evaluations of responses to a major outage or exercise and shall reflect relevant changes to the plan.

4.10.2. Annual Exercise. The Utility Manager shall conduct an exercise annually using the procedures set forth in this emergency plan. If the BVES uses the Emergency Response Plan during the twelve-month period in responding to an event or major outage, the annual exercise is not required for that period. However, the Utility Manager should also evaluate whether or not staff would benefit from the exercise regardless of the fact that the Emergency Response Plan was utilized within the previous 12-month period. For example, if a major change to the Outage Management System is installed since the last Emergency Response Plan activation, it would be appropriate to at a minimum exercise that portion of the plan.

4.10.3. Exercise Notice. The Utility Manager shall provide no less than ten days' notice of the annual exercise to appropriate state and local authorities, including the CPUC, state and regional offices of the OES or its successor, the California Energy Commission, and emergency offices of the counties in which the exercise is to be performed.

4.10.4. Exercise Evaluation. The response to an exercise or major outage shall be evaluated per Section 4.9. The evaluation shall be provided to Regulatory Affairs Manager so that it may be forwarded to the CPUC as part of the report required by GO-166 Standard 11.

4.10.5. Emergency Response Outreach Training. The Utility Manager shall conduct outreach with the county and city emergency response officials and participate as applicable in other emergency exercises designed to address problems on electric distribution facilities or services, including those emergency exercises of the state and regional offices of the OES or its successor, and county emergency offices.

4.11. **Initial Notification.** The Utility Manager shall ensure that the notifications in accordance with the requirements provided in BVES's Electric Utility Emergency Reporting Policy and Procedures are achieved within the required timeframes.

5. Emergency Response Communications Plan.

5.1. **Strategy Overview.** Achieving unity of effort provides for the most effective and efficient emergency response. This is best attained through the "4 C's" of disaster planning:

- Collaboration
- Cooperation
- Coordination
- Communication

The first three hinge upon effective communications. The overall communications strategy is structured so that all stakeholders receive accurate, timely and consistent information, with an overall message for safety of the public, employees and contractors. Communications with local government agencies, customers and other stakeholders are vital to the successful implementation of the EDRP. The plan aims to identify who should be given specific information, when that information should be delivered, and what communication channels shall be used to deliver the information.

During a major outage the Operations Group shall make it a priority to provide the following information to the Public Information Group:

- **Extent of the outage** – using our Outage Management System (OMS) and available field assessment and data, determine how many customers are affected and in which areas
- **Cause of the outage** – provide in broad terms. If unknown, provide status of crews responding to investigate including updating once the power has been restored.
- **Estimated time of restoration (ETR)** – this is the key information customers want to know. If unknown, state so and update as more information becomes available. Don't let ETRs become stale (for example, if a posted ETR is extended, update the posting with a revised ETR).

The Customer Service Supervisor is responsible for updating and executing the BVES communications plan in support of the EDRP. The Utility Manager is responsible for ensuring that accurate information from the Operations Group flows to staff responsible for executing the communications plan.

Additionally, the Customer Service Supervisor shall maintain "call center metrics" that measure customer access to information on customer service calls and web host availability during an emergency or disaster.

5.2. **Establish Multiple and Effective Communication Channels.** Establishing a multilayered communications plan utilizing many separate communications channels is essential to ensuring that the communications plan shall be effective in reaching targeted audiences under uncertain and severe conditions, as would be expected for major outages and disasters and/or following such events. For example, some customers may lose their landline capability in a power outage but still have cell phone service. Plan resiliency, therefore is dependent on having many overlapping layers of communications.

5.2.1. Outbound Communications

- BVES website
- BVES social media
- Online meetings/broadcasts
- Interactive Voice Response System
- Press releases to local media
- Press conference
- Phones – landlines, mobile cellular, and satellite lines
- Email
- Two-way text messaging
- Door hangers
- Keeping staff who interact with customers informed with latest message
- Advertising
- Community workshops and presentations
- Mail (for example, flyers, newsletters)
- Bill inserts
- County and City communication systems
- Big Bear Chamber of Commerce email blast
- City email blast
- Bear Valley local government, agencies and utilities Public Information Group

5.2.2. Inbound Communications:

- Interactive Voice Response System
- Call center phone lines
- BVES social media
- Customer service windows
- Bear Valley local government, agencies and utilities Public Information Group
- Phones – landlines, mobile cellular, and satellite lines
- Email
- Text messaging
- Activate internal PSPS list
- Press inquiries
- iRestore Reports

5.2.3. Internal Communications:

- Phones – landlines, mobile cellular, and satellite lines
- Email
- Text messaging
- FaceTime, Skype, Online Meetings, etc.
- Intranet – shared drives, internal applications, and SharePoint
- Radios – VHF

- Direct reports

5.2.4. There are many developing and evolving communications technologies; therefore, it is essential that staff continually evaluate the above lists and modify as applicable. Changes should be evaluated each time the plan is updated.

5.2.5. Besides having multiple communications channels, there are three other elements that are essential to ensuring an effective communications strategy:

- Testing and exercising the communications channels frequently so that staff are trained on their usage, target audiences and key stakeholders are familiar with them, and technical issues are resolved prior to an actual emergency. Once testing and exercising of communication channels is complete, adjustments will be made based on lessons learned.
- Establishing good business relationships and rapport with target audiences and key stakeholders prior to any emergency.
- Maintaining accurate contact information with key stakeholders per Section 3.11 (Key External Contacts List) of this plan.

5.3. **Conduct Pre-Incident Outreach and Education.** BVES has developed a multi-level approach to community education and outreach related to public awareness of outages, emergencies, and emergency preparedness. An important aspect of managing expectations is to conduct education and outreach with customers and key stakeholders well in advance of any emergency. This allows target audiences the opportunity to be ready and provides them the knowledge of what to expect and how to prepare in the event of an emergency such as an extended outage due to a major winter storm or other natural disaster. *A community that is knowledgeable and ready for emergency events will be a force multiplier in emergency response actions*.

5.3.1. City and County Outreach. The Utility Manager shall coordinate with city and county officials in compliance with Public Utilities (P.U.) Code Section 768.6, which requires the following outreach by BVES:

- In developing and adopting an emergency and disaster preparedness plan, BVES shall invite appropriate representatives of every city and county within the BVES service area to meet with, and provide consultation to BVES.
- BVES shall provide the point of contact designated by the city and county with an opportunity to comment on draft emergency and disaster preparedness plans.
- Every two years, in order to update and improve BVES's emergency and disaster preparedness plan, BVES shall invite appropriate representatives of every city and county within its service area to meet with, and provide consultation to BVES. All recommendations and input will be considered and updated should it be determined to be beneficial for the EDRP. The meeting shall be noticed and shall be conducted in a public setting that allows for the participation of appropriate representatives of counties and cities within the BVES service area. Participating counties and cities shall be provided with the opportunity to provide written and verbal input regarding BVES's emergency and disaster preparedness plan. For purposes of this public meeting, BVES may convene a closed meeting with

representatives from every city and county within its service area to discuss sensitive security-related information in BVES's emergency and disaster preparedness plan and to solicit comments.

- BVES shall notify the commission of the date, time, and location of the above meeting. BVES shall memorialize the meeting and shall submit its records of the meeting to the commission.
- BVES may comply with the meeting requirement that is ordered by the Public Utilities Code by : i) making a presentation regarding its emergency and disaster preparedness plan at a regularly scheduled public meeting of each disaster council created pursuant to Article 10 (commencing with Section 8610) of Chapter 7 of Division 1 of Title 2 of the Government Code within BVES' service area; or ii) at a regularly scheduled public meeting of the governing body of each city located within the service area.

5.3.2. General Public, Customer and Stakeholder Outreach and Education (before an emergency). Utilizing BVES website, social media, public workshops, meetings with key stakeholders, press releases, advertising, newsletters, bill inserts, two-way text communication, IVR, and other communications channels, the Utility Manager and Customer Service Supervisor shall work to educate, inform and conduct outreach with the general public, customers and stakeholders such as local government and agencies, community groups and other utilities on the following topics:

- Customer power outage readiness preparation, including publishing a customer checklist for outages
- Backup generators and safety training
- Reporting outages
- Reporting wire down events and how to handle the situation
- Public Safety Power Shutoff policies
- Wildfire prevention measures including the vegetation management, covered wire, and distribution system inspection programs
- Operational initiatives that support wildfire prevention efforts such as re-closer and circuit patrol policies
- Outage restoration strategies used by BVES
- Infrastructure projects to improve safety, reliability and mitigate wildfires
- Other topics as deemed appropriate by the Utility Manager and/or Energy Resources Manager

In addition to the above outreach, the Utility Manager shall endeavor to periodically brief key elements of the EDRP at Big Bear Valley Mountain Mutual Aid Association ("MMAA") meetings, Big Bear Joint Utility meetings, Big Bear Fire Department and Sheriff's Department leadership.

The Utility Manager and Customer Service Supervisor shall develop and implement a strategy to periodically brief local government and agencies on BVES' emergency response plan. During these interactions, it is important to establish business relationships with local government and its agencies, other key community stakeholders, and other utilities so that during emergencies the BVES Leadership Team may seamlessly engage these groups. The

Utility Manager and Customer Service Supervisor shall develop a contact list of the key staff at local government and agencies to notify during emergency events. The contact list should include preferred and back-up means of contact (for example, mobile phone number, email, office phone, etc.). The contact list shall be verified, corrected and updated as necessary at least every six months by the Administrative Support Associate.

The list of local government and agencies and key stakeholders shall include at a minimum the following organizations:

- Local officials (City of Big Bear Lake (CBBL) and San Bernardino County)
- State officials (normally CPUC Energy Division and Safety Enforcement Division)
- San Bernardino County Office of Emergency Services (County OES)
- Big Bear Fire Department
- California Department of Forestry and Fire Protection (CAL FIRE)
- U.S. Forest Service
- San Bernardino County Sheriff's Department Big Bear Lake Patrol Station
- California Highway Patrol (CHP) Arrowhead Area
- California Department of Transportation (Caltrans)
- Big Bear Area Regional Wastewater Agency (BBARWA)
- Big Bear City Community Services District (CSD)
- Big Bear Lake Water Department (DWP)
- Big Bear Municipal Water District (MWD)
- Southwest Gas Corporation
- Bear Valley Community Hospital
- Bear Valley Unified School District
- Big Bear Chamber of Commerce
- Big Bear Airport District
- Big Bear Mountain Resort
- Local communication companies (Spectrum and various cell providers)

5.4. **Provide Outreach in Prevalent Languages.** United States Census data shows that the top three primary languages used in California are English, Spanish and Chinese (including Cantonese, Mandarin and other Chinese languages). BVES shall communicate its emergency preparedness outreach and response in English, Spanish, Chinese (including Cantonese, Mandarin and other Chinese languages), Tagalog, and Vietnamese. Additionally, BVES has included two indigenous languages (Zapateco and Mixteco) as part of its wildfire mitigation communications.

5.5. **Provide Emergency Incident Communications.** Utilizing the multiple communications channels discussed earlier, the Public Information Group and Emergency Response Leadership Team shall engage and educate the general public, local government and its agencies, and other key stakeholders to provide notification of outages and emergencies, estimated time to restore service, cause of outage (if known), and periodic updates as appropriate. The following sections provide detail on how these communications shall be conducted.

5.5.1. Set Expectations and Develop Trust. When an emergency occurs, BVES shall communicate with the general public, customers, local government and its agencies, and key stakeholders as soon as possible to set expectations and address emergency issues. When business operations or households are disrupted by power outages, customers expect to know how long they shall be impacted. Thus, estimated restoration times (ETRs) shall be developed, monitored, adjusted and communicated. Establishing ETRs is a key function of the Operations Group. Regulators and local government officials shall be notified regarding the impact to communities per GO 166 Standard 6. Customer Service Supervisor shall:

- Work with BVES's public relations contractor subject matter experts (SMEs) to develop consistent and accurate BVES messaging to customers and stakeholders.
- Employ consistent and frequent multi-channel communications to disseminate information that leverage and reinforce one another.
- Brief employees; especially field staff and customer service representatives, on the latest information so that their interactions with the public are consistent with the messaging.
- Coordinate closely with the Operations Group to provide customers and stakeholders system updates including best known restoration times.
- Ensure that all communications are accurate and always factually correct. If incorrect information is inadvertently issued, then it is important that a correction be issued as soon as known and that the error be acknowledged. If information is not certain, then avoid reporting it or qualify it as appropriate. For example, "BVES has received reports of a downed tree on its power lines on Moonridge Road; field crews have been dispatched to validate the report and assess any damage that may have resulted."
- Strive to be transparent; it is absolutely critical to our credibility and to ensuring that the public, customers and stakeholders have the upmost confidence in our ability to perform our essential public service – providing safe, reliable, and high quality electric service.
- Per GO 166 Standard 6, BVES shall provide an initial notification within one hour of the identification of a major outage or other newsworthy event. BVES shall also notify the Commission and San Bernardino County Warning Center at the Office of Emergency Services of the location, possible cause and expected duration of the outage. The Warning Center at the OES is expected to notify other state and local agencies of the outage. Subsequent contacts between state and local agencies and BVES shall be conducted between personnel identified in advance, as set forth in Standard 4.B (Communications Strategy with Government). From time to time the Commission staff may issue instructions or guidelines regarding reporting.

5.5.2. Notify and Engage Key Stakeholders. Keeping local government and agency officials as well as other key stakeholders informed of emergencies is critical to their ability to operate and support their missions. It is far more advantageous for these officials and key stakeholders to receive information directly from BVES Leadership in a timely manner rather than via the media.

Utilizing the contact list developed during pre-incident engagement, BVES Leadership should notify local government and agencies and other key stakeholders of emergencies and provide them updates as appropriate. Some of this notification may be achieved by sending to the local "Public Information Officer" developed through MMAA group email notifications and status updates.

5.5.3. Notify Customers and General Public. The Customer Service Supervisor shall develop pre-planned statements with fill-in-the-blank sections for potential outage and emergency events. These pre-planned statements shall be used as deemed appropriate by the Customer Service Supervisor to update customers and the general public as soon as feasible via the following means:

- News releases (newspaper, online news outlets, radio, etc.)
- Website updates
- Social media updates
- IVR messages
- Two-way text communication
- Email notifications to customers
- Other public and customer engagement media (for example, City of Big Bear Lake's email blast)

Specific guidance on developing press releases and statements and engaging the media is provided in the next section. Customer Service Supervisor shall develop pre-planned statements for IVR and text message use. IVR and text messages should be short – about one sentence – and may refer the customer to additional information sources such as our website or social media. For example, "BVES crews are responding to outages on the North Shore and the estimated time to restore power is 2 pm – additional information is available at www.bves.com."

5.5.4. Media Engagement Procedures. By proactively engaging the media, BVES is able to reach a wide audience in its service area and establish the opportunity to convey the correct narrative and information to the general public. When engaging the media, it should be understood that in general the media are:

- Professionals at what they do – they are normally just doing their job and are experts at interviews.
- Often, they are deadline driven.

Therefore, when working with the media as a BVES spokesperson, staff must be prepared and properly authorized. Any employee speaking to media whether "on the record" or "off the record" automatically becomes a spokesperson for the BVES willingly or unwillingly.

5.5.4.1. *Authorized Media Engagement*. The Public Information Group is the authorized group to interact with the media and they shall lead all media engagement efforts. They shall work closely with the Operations Group to ensure they have accurate information, develop press releases with the assistance of the BVES's public relations firm, coordinate releases with other organizations such as local government and agencies, and clear press releases with the President prior to releasing them.

It should be recognized that media representatives could reach out to BVES employees at any time; especially, BVES employees (and their contractors) out in the field. Therefore, Managers and Supervisors must ensure their employees are periodically updated with the status of the emergency response and train their employees to respond to direct media reporter inquiries as follows:

- At all times act politely and professionally.
- Write down the reporter's name, organization, and phone number.
- Write down any questions the reporter may have.
- It is acceptable for field crews and staff to respond to questions directly pertaining to the conditions or work being performed by them. For example, it is acceptable for field crews to describe how the weather is impacting their immediate restoration work out in the field.
- However, any larger questions, such as estimated time of restoration, other reported outages, availability of resources (manpower and materials), restoration strategy should be written down and the reporter informed that BVES shall get back to them.
- In all cases, the employee approached by the media must inform their Supervisor or Manager as soon as possible of the inquiry and pass along the contact information, questions asked, and any answers provided. This information must be immediately conveyed to the Public Information Group.
- The Public Information Group should follow up as soon as feasible with the reporter even if the employee responded to the questions.

5.5.4.2. *Press Release Content*. The Public Information Group shall develop press releases from pre-planned press release templates as feasible. These are especially useful in the initial stages of an emergency where information is still sparse. They allow for rapid dissemination of initial information of the emergency scope. As the Operations Group obtains more accurate information from Field Crews, the press releases should be updated accordingly. Additionally, they shall consult with BVES's public relations contractor to develop press releases and an engagement strategy tailored to the specific emergency.

Press releases should make the best attempt at addressing the "who, where, why, what, when, and how" to the emergency event. However, do not delay issuing a press release to obtain all of this information. The information can be relayed in press release updates. Ideally, in a large outage, the following information should be released as it is known:

- **(Who/where)** Location of the outage and who is affected – use geographic locations such as areas or streets (for example, "Moonridge Area", "from the Village to the Dam on the South shore of the lake", "from Pine Knot Ave to Paine Rd on the South Shore of Big Bear Lake", etc.). Avoid using circuit and/or substation names to describe the location, since these names have little meaning to the public.
- **(When)** Time outage started and estimated time of restoration (ETR).
- **(Who)** Number of customers without power. Provide the best estimate available and update as it is changed.
- **(Why/what)** Cause of the outage and location of damage/problem. Use simple descriptions that a non-utility audience would understand (for example, "car hit a ground mounted transformer causing sufficient damage to take it out of service," "an 80-foot tree fell from across the street on Pine Knot Ave onto a major overhead power line," "loss of power supply from Goldhill due to fault on Southern California Edison equipment," etc.).

- **(When)** Whether or not Field Crews are conducting repairs to restore power. If crews are not on site, provide an estimated time of arrival if available.
- **(How)** Actions being taken to restore power (starting BVPP, conducting field switching to alternate sources of power, conducting repairs to damaged equipment, etc.).

Pictures of the damage and field crews conducting repairs are always very useful.

5.5.4.3. *<u>Press Release Protocols</u>*. The Public Information Group under the leadership of Customer Program Specialist shall be responsible for drafting and issuing press releases from the BVES to the media. Press releases shall be drafted, approved, and released per the protocol shown in Figure 5-1, Press Release Protocol.

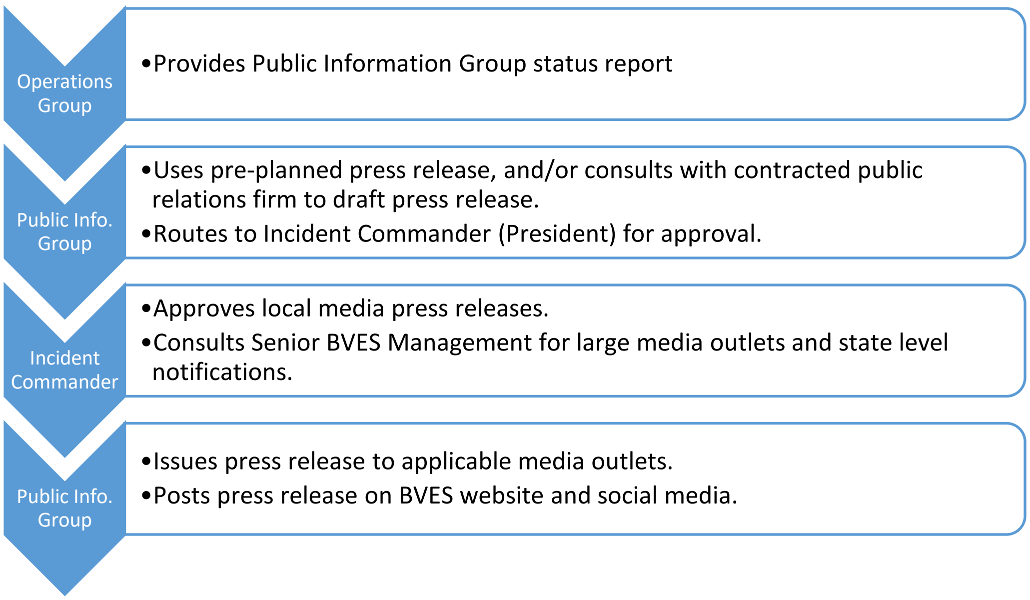

Figure 5-1: Press Release Protocol

5.5.5. <u>Post Emergency Event Close-out Statement</u>. Once the Emergency Response is determined to be no longer necessary, Customer Service Supervisor shall prepare a summary press release and statement providing customers a brief summary of the emergency event and provide any post incident support instructions such as:

- Information on whom to contact at BVES to reconnect service for customers whose weather head or other equipment was damaged preventing immediate service restoration.
- Information on obtaining post incident customer support per Section 6 of this plan.

5.6. **Reports to the Commission.** The Utility Manager shall ensure required reports to the Commission and its Divisions are made in a timely and complete manner. These reports include:

- Notify California Public Utilities Commission (CPUC) and Warning Center at the Office of Emergency Services San Bernardino within one hour of an outage if the outage meets the major outage criteria of GO-166.

- Notify President Safety Enforcement Division (SED), CPUC within twelve hours of the power being shut-off per ESRB-8.
- Provide a report (written) to President of SED no later than 10 business days after the shut-off event ends per ESRB-8.

6. **<u>Customer Support in Emergencies.</u>** In the event the Governor of California declares a state of emergency because a disaster has either resulted in the loss or disruption of the delivery or receipt of utility service and/or resulted in the degradation of the quality of utility service, BVES shall implement certain customer service actions as described below. This section provides an overview of the protocols for compliance with requirements adopted by the CPUC regarding activities to support customers. The protocols span customer billing, support for low income, life support, Access and Functional Needs (AFN) customers, and other forms of customer support.

6.1. **Support for Low Income, Life Support and AFN customers.** The Customer Care Team shall freeze low income, life support, and AFN customer accounts and stop all California Alternative Rates for Energy (CARE) High-Usage tracking. The Supervisor shall work with implementation contractors and emergency assistance programs to update affected customers on eligibility requirements and enroll them in assistance programs.

6.2. **Billing Adjustments.** The Customer Care Team shall freeze accounts and stop billing during the disaster event to ensure bills are not estimated or generated for affected customers. Billing shall resume once the case is closed by the Customer Care & Billing (CC&B) technical team, upon notice from the Supervisor.

6.3. **Deposit Waivers.** The Customer Care Team shall add a designated customer contact for all affected customers. The contact shall reside within CC&B for up to one year from the date the emergency ends. This shall allow BVES to easily track the customer's account, so when service is re-established, the utility shall know to waive any associated fees and to expedite customer re-connection.

6.4. **Extended Payment Plans.** The Customer Care Team shall freeze all payments on affected customers' account to avoid affecting their credit. All affected customers shall be notified that an extended payment plan option is available for any past due payments.

6.5. **Suspension of Disconnection and Nonpayment Fees.** The Customer Care Team shall freeze affected customer accounts, so disconnections and nonpayment fees are not generated during the disaster event. Once the emergency ends, the Supervisor and/or Specialist shall contact the CC&B Team to "close" all affected customer cases. This shall automatically transition the customer's account back to the normal state. BVES shall simultaneously begin assisting with service restoration and deposit waivers.

6.6. **Repair Processing and Time**. During emergencies, BVES shall set up specialized repair teams to expedite repair processing. If additional support is needed, BVES shall leverage mutual aid programs with other emergency response resources and shall work with electrical contractors to ensure timely service restoration. Exact timing shall be dependent on the nature of the situation.

6.7. **Access to Utility Representatives.** The BVES Engineering Technician shall arrange for connections and facilitate expedited services. Leveraging its IVR system, BVES shall be able to handle thousands of phone calls simultaneously and divert customers to the appropriate utility representative.

6.8. **Access to Outage Reporting and Emergency Communications.** During emergencies, BVES shall invoke its emergency communications plan per the EDRP to attempt to reach as many customers as feasible with outage, restoration and recovery information via multilayered communications channels and multiple languages per Section 5.4 of the EDRP.

Appendix G. **BVES Public Safety Shutoff Plan**

Bear Valley Electric Service, Inc.
Public Safety Power Shutoff Plan

March 5, 2025

Approved by: ____

Paul Marconi, President, Treasurer & Secretary

Bear Valley Electric Service, Inc.
Public Safety Power Shutoff Plan

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1. Purpose and Overarching Guidelines

1.1. Purpose of PSPS. The purpose of proactive de-energization is to promote public safety by decreasing the risk of utility infrastructure as a source of wildfire ignitions. Generally, proactive de-energization will be referred to as Public Safety Power Shutoff ("PSPS"), which is consistent with the terminology used by the major California investor-owned utilities. As a measure of last resort, PSPS activation is consistent with the statutory obligation to protect public safety pursuant to Public Utilities Codes ("PUCs") § 451 and 399.2(a).

1.2. Purpose of the PSPS Plan. This document, herein referenced as the ("Plan"), provides the policies and procedures of Bear Valley Electric Service, Inc. ("BVES" or "Bear Valley") with regard to PSPS and addresses the following operational issues:

- PSPS advance planning, personnel training, and preparations prior to the fire season.
- Procedures leading up to, during, and following extreme fire threat weather events in which PSPS may be invoked. These include BVES's operational fire prevention actions and procedures.
- Public outreach, coordination with local and government officials, advisory boards, public safety partners, representatives of people/communities with access and functional needs ("AFN"), tribal representatives (if applicable), senior citizen groups, business owners, and public health and healthcare providers including those with medical needs. This includes a Community Resource Center ("CRC") and communications regarding PSPS.
- Established guidelines with continuous learning for PSPS exercises.

1.3. Measure of Last Resort. BVES must only deploy PSPS as a ***measure of last resort*** and must justify why PSPS was deployed over other possible measures or actions. This plan provides the course of action to be followed prior to enacting a BVES initiated PSPS, demonstrating that enacting a PSPS is the measure of last resort.

Customer Engagement. BVES will work to engage its customers and other impacted stakeholders to promote understanding of the purpose of PSPS actions, BVES's process for initiating it, how to safely manage a PSPS event, and the impacts if deployed.

1.4. PSPS Coordination. Deploying PSPS requires a coordinated effort across multiple state and local jurisdictions and agencies. Coordination in preparation for PSPS is a shared responsibility between BVES, public safety partners, and local governments; however, BVES is ultimately responsible and accountable for the safe deployment of a BVES PSPS. BVES must work with the California Governor's Office of Emergency Services to integrate its warning programs with the agencies and jurisdictions within California that have a role in ensuring that the public is notified before, during, and after emergencies. Throughout this document, the collective phrase "Local Government, Agencies, and Partner Organizations" includes applicable local government and agencies, utilities, key non-government and commercial entities, and also includes critical facilities and critical infrastructure. Further discussion is provided in Section 5.

1.5. PSPS Is an Emergency. Consequences of a BVES PSPS should be treated in a similar manner as other emergencies that may result in loss of power, such as earthquakes or floods.

1.6. Reporting and Continuous Improvement. BVES must report on lessons learned from each BVES PSPS event, including instances when PSPS protocols are initiated by BVES, but de-energization does not occur, to continually improve BVES's PSPS practices.

BVES must work together with the other utilities to share information and advice to create effective and safe PSPS programs at each utility and ensure utilities are sharing current and accurate information with public safety partners.

2. Chain of Responsibility

2.1. President holds overall responsibility for the PSPS Plan and ensuring it is properly implemented, resourced, trained upon, executed, and updated as appropriate. Furthermore, the President shall ensure proper communications and coordination with local government, agencies, and customers.

2.2. Utility Manager is responsible for executing the following actions under BVES PSPS Plan (in the absence of the Utility Manager, the President will fulfill the responsibilities of the Utility Manager):

- Direct emergency operations under this Plan and the EDRP;
- Ensure monitoring of fire potential index (FPI), weather forecasts, and actual weather conditions are properly conducted by appropriate staff;
- Direct the operational activities related to system line-up and PSPS as warranted;
- Ensure Field Operations staff provide timely and accurate information to the Customer Service Supervisor and other staff performing customer and public information functions;
- Work closely and coordinate with counterparts at local government and agencies leading up to a PSPS event, during PSPS, and during restoration procedures;
- Activate the Wildfire Response Team (WRT) for PSPS procedures
- Determine the appropriate staff composition of the WRT when activated;
- Train or assign training to BVES staff with roles required by this Plan;
- Ensure resources are available to properly execute this plan and identify any gaps in resources to the President as well as proposed remedies;
- Ensure all regulations are followed and required reports are timely submitted to the applicable regulatory bodies, including the Commission and Energy Safety;
- Evaluate whether changes to this plan are warranted and implement any necessary changes.

2.3. Field Operations Supervisor is responsible for executing or directing operations in the field, including:

- Monitor (or direct monitoring) weather advisories, consultant forecasts, and the FPI forecast at least daily;
- Direct and manage operational system line-ups based on conditions as described in this plan;
- Direct and coordinate PSPS procedures in this plan;
- Direct the activities of the WRT;
- Control all switch and system lineup operations;
- Provide (or ensure) timely and accurate information to the Customer Service Supervisor and/or other staff performing customer and public information functions;
- Inform the Utility Manager of any system issues;
- Collect relevant data and maintain documentation including, but not limited to, inspections, operational system lineup, and PSPS activities; and
- Submit to the Utility Manager recommended changes to this Plan as warranted.

2.4. Utility Engineer & Wildfire Mitigation Supervisor are responsible for fire prevention planning and engineering design of the electric distribution, sub-transmission and substations, including:

- Ensure system design and construction is in compliance with applicable government rules and regulations to mitigate fire;
- Develop distribution, sub-transmission, and substation designs to reduce fire risk;
- Research, evaluate, and source materials fire resistant materials and equipment;
- Develop device protective settings and select fuses to enhance fire prevention while taking into account reliability and the served load;
- Support Field Operations and the WRT as directed by the Utility Manager in the execution of system operations per this plan; and
- Submit recommended changes to this plan to the Utility Manager as warranted.

2.5. Wildfire Mitigation & Reliability Engineer, under the supervision of the Utility Engineer & Wildfire Mitigation Supervisor, will monitor Bear Valley's Wildfire Analyst Enterprise (WFA-E) fire risk (Fire Behavior Index and other applicable consequence models) and the FPI model. The Wildfire Mitigation & Reliability Engineer will send the forecasts (WFA-E fire risk) and FPI to designated Field Operations and Management staff (President, Energy Resource Manager, Utility Manager, Field Operations Supervisor, Utility Engineer & Wildfire Mitigation Supervisor, Electrical Distribution System Engineer, Customer Programs Specialist, Substation Technician), and other staff as designated by the Utility Manager. In the absence of the Wildfire Mitigation & Reliability Engineer, the above action will be performed by the Electrical Distribution System Engineer or the GIS Specialist as designated by the Utility Engineer & Wildfire Mitigation Supervisor.

2.6. Customer Program Specialist, under the supervision of the Customer Service Supervisor and the Energy Resource Manager, is responsible for the BVES Communications Plan, including:

- Notify (or direct to notify) local government, agency, and customer notifications under this plan;
- Establish and maintain customer communications methods and systems equipment to support proactive de-energization notifications per this plan;
- Train staff assigned to issue customer and public information via media notification statements and customer communications methods;
- Developing (or causing to be developed) the contact list of local government and agencies per this plan;
- Direct a customer education strategy to inform customers about BVES's fire mitigation programs, including PSPS; and
- Submit to the Utility Manager recommended changes to this plan as warranted.

3. Considerations for Plan Activation

3.1. Considerations for PSPS Plan Activation. The BVES service area is susceptible to several conditions in which BVES may activate its PSPS Plan. These are:

- Extreme fire threat weather and fuel conditions in BVES's service area that warrant BVES to implement PSPS on BVES-owned and operated power lines in some or all areas of its service area.
- Extreme fire threat weather and conditions outside of the BVES's service area, in which Southern California Edison (SCE) directs a PSPS on SCE-owned/operated power lines leading to a partial or complete loss of the three SCE supply lines into the BVES service area. This threat is higher than the likelihood that BVES initiates its own PSPS due to the greater presence of extreme fire threat weather and fuel conditions across SCE's territory than in the BVES service area. In such a case, BVES would seek to supply power to its customers using all available power resources.
- In the circumstance that a PSPS is warranted in some or all areas of the BVES service area and SCE has implemented PSPS actions that result in a partial or complete loss of supplies to the BVES service area.

4. BVES Fire Prevention Procedures

4.1. Fire Prevention.

4.1.1. Bear Valley's Wildfire Mitigation Plan provides descriptions of system hardening projects, operations and maintenance programs, and other initiatives being pursued by BVES to mitigate wildfire. This PSPS Plan is an extension of the Wildfire Mitigation Plan's fire prevention efforts.

4.1.2. As system improvements are made and environmental conditions change, the plan will evolve to meet these changes. In creating the Plan, BVES has incorporated the input and interests of our stakeholders to ensure that the needs of the community are effectively met while mitigating the risk of wildfire. Community outreach and communications are a key component of this Plan, as well as maintaining partnerships with the Big Bear Valley Mountain Mutual Aid Association, City of Big Bear Lake, San Bernardino County, Big Bear Fire Department, Big Bear Lake Sheriff's Department, other local agencies, local utilities, local radio stations, news media, and the public.

4.1.3. PSPS is an operational safety measure of last resort to prevent wildfires. It is logical that the PSPS Plan includes Bear Valley's operational fire prevention plan measures so that the progression of operational steps to be taken by BVES staff is properly sequenced and understood by all stakeholders.

4.1.4. Regulatory Background

Ordering Paragraph 5 of D.12-01-032 required BVES to prepare a Fire Prevention Plan to identify the occurrence of 3-second wind gusts that exceed the structural and mechanical design standards for overhead power-line facilities.

D.14-05-020 modified D.12-01-032 by eliminating the requirement to identify 3-second wind gusts in real time, provided a utility will still address the situation when all three of the following conditions occur simultaneously:

(i) 3-second wind gusts exceed the structural or mechanical design standards for the affected overhead power-line facilities,
(ii) these 3-second gusts occur during a period of high fire danger, and
(iii) the affected facilities are located in a high fire-threat area.

D.14-05-020 also required utilities to identify the specific parts of their service territories where all three conditions listed in Ordering Paragraph I (a) occur simultaneously, based on a minimum probability of 3% over a 50-year period that 3-second wind gusts that exceed the design standards for the affected facilities will occur during a Red Flag Warning in a high fire-threat area. Ordering Paragraph 2 of D.17-12-024 requires each electric investor-owned utility have a fire prevention plan for facilities in the High Fire-Threat District containing the information specified in General Order ("GO") 166, Standard 1, Part E, to the extent applicable to the electric utility's service area and to file a report containing the fire prevention plan annually beginning October 31, 2018.

4.1.5. This Plan lists and describes the operational fire prevention measures BVES intends to implement to mitigate the threat of power-line fires generally and in the situation where all three of the conditions listed in GO-166, Standard 1, Part E occur simultaneously. BVES has identified areas potentially susceptible to these conditions. These areas are heavily forested, abundant in available fuel, and could threaten the system when high winds occur. When these conditions exist, BVES has pre-identified areas that are targeted for PSPS in Appendix B.

4.2. Seasonal Considerations. Understanding BVES' system demand, service area environmental factors, and wildfire risk drivers allows BVES to operate the system in a manner that is optimized for public safety including wildfire mitigation, reliability, and increased quality of service delivered.

The non-winter months (April through October) bring the following characteristics to BVES's service area:

- Lower load demand due to reduced or minimal tourism and no ski resort snowmaking, therefore BVES' load is generally lowest in April, May, September, and October; the load increases somewhat in the summer months of June, July, and August;
- Higher ambient temperatures with low humidity that rarely require air conditioning; and
- Higher wildfire risk due to low moisture content in the service area and increased presence of fuel (dry vegetation).

Therefore, during the winter months, as described above, the BVES distribution system is optimized for safety and reliability. Following the winter season, the system's operational focus is more defensive and optimized almost entirely for fire prevention.

4.3. Daily-to-Real-time Considerations. The daily and even hourly changes in environmental and system conditions can change the risk of wildfire significantly. Therefore, the factors affecting Daily-to-Real-time considerations must be understood and evaluated by the Operations Team to develop the appropriate risk mitigation package on a daily or even more frequently when adverse factors develop or are expected to develop. Some of the factors that the Operations Team needs to consider are:

- **Forecasted and actual weather:** Sustained wind speed, wind gust strength, dryness (humidity), precipitation, etc.
- **Fuel inventory:** Buildup of ground cover vegetation, timber on the ground, thickness of forest, etc.
- **Dryness of fuel:** Dryness of dead vegetation, timber on the ground, etc.
- **System design limitations:** Installed bare conductor configuration, conventional expulsion fuses installed in the system, switches with limited protective and remote control capabilities, etc.
- **T&D equipment failure or degradation:** Protective switch failure, loss of remote connectivity with protective devices, etc.
- **Missed or delayed inspection:** Detailed inspection or patrol per GO-95 missed or delayed, GO-174 inspection missed or delayed, other inspection deemed critical missed or delayed, etc.
- **Delayed correction of fire hazard inspection discrepancies:** Correction of "must be fixed before fire season" discrepancies, GO-95 discrepancies not corrected within required periodicity, etc.

- **Operational deviations from normal lineup:** Abnormal system lineup due to planned maintenance, system upgrades, equipment degradation, etc.
- **Degradation in situational awareness:** Failure or loss of connectivity with installed weather stations, loss of FPI model, loss of WFA-E application, loss of NFDRS (e.g., during Federal Government shutdown), loss of remote circuit monitoring, loss of HD Alert Camera coverage, etc.
- **Resource degradation:** Insufficient line crews and/or other key operation staff, loss of utility vehicles, etc.

Daily-to-Real-time considerations always override seasonal considerations.

4.4. Pre-Planned Operational Posture. The operational actions to be taken for forecasted and actual weather, fuel inventory, dryness of fuel, and system design limitation consideration factors are easily pre-determined. Whereas the response to the rest of the Daily-to-Real-time consideration factors must be individually evaluated to determine their impact on the overall plan. For example, if certain weather stations suffer a failure, the Utility Manager may require the Wildfire Response Team be deployed sooner in a high wind situation.

4.4.1. **Operational Posture**: Bear Valley's entire service area is within the HFTD. From approximately mid-November to April, Bear Valley will generally experience winter storms with a seasonal average of approximately 58 inches of snow. Therefore, during the winter weather the threat of wildfire is less likely and reliability of power to customers during freezing weather is of concern.

Based on the above Bear Valley's reclosing posture is as follows:

- All Year Round:
  - ARs to underground circuits are placed in "Manual" mode of operation (e.g., they will not shut and test upon detecting a fault).
  - ARs to overhead circuits that are 70% or more covered conductors are placed in "Manual" mode of operation (e.g., they will not shut and test upon detecting a fault).
  - ARs that are not connected to the SCADA network shall be placed in "Manual" mode of operation (i.e., they will not shut and test upon detecting a fault).
  - Fuse TripSavers that are not connected to the SCADA network shall be placed in "Manual" mode of operation (i.e., they will not shut and test upon detecting a fault).

- April 1st to October 31st:
  - All ARs are placed in "Manual" mode of operation (e.g., they will not shut and test upon detecting a fault).
  - All Fuse TripSavers shall be placed in "Manual" mode of operation (i.e., they will not shut and test upon detecting a fault)

- November 1st to March 31st:
  - SCADA connected ARs may be placed in "Automatic" mode of operation (e.g., three trips to lockout) at the direction of the Field Operations Supervisor when the FPI is "Moderate" or lower.
  - SCADA connected Fuse TripSavers may be placed in "Automatic" mode of operation (e.g., three trips to lockout) at the direction of the Field Operations Supervisor when the FPI is "Moderate" or lower.

If an AR is Pulse Condition capable and is placed in "Automatic", the Pulse Condition feature shall be enabled.

When an Auto-Recloser, Switch, or Fuse TripSaver that is in "Manual" trips open, the affected portions of the de-energized circuit or feeder will be patrolled prior to re-energizing them. If the cause is identified and the FPI is "Very Low" or "Low," the Field Operations Supervisor may authorize the Line Crew to test the device once. If the device trips open again, the circuit or feeder must be thoroughly patrolled to determine the fault and ensure there is no risk of causing fire.

4.4.2. **Daily-to-Real-time Operational Posture**: The pre-planned operational postures provided in this section take into account the System Design Limitations factor.

BVES' forecasting framework for fire prevention measures relies on use of a Fire Potential Index (FPI) model produced by Technosylva specifically customized for the BVES service area. The FPI model quantifies the fire activity potential over the territory based on different parameters including fuels, terrain, and weather. Table 4-1: Fire Potential Index provides the following categories of FPI:

Table 4-1: Fire Potential Index

FPI categories	FPI value	FPI percentile
Very Low	< 5	<60
Low	5-10	60-80
Moderate	10-13.5	80-85
High	13.5-23	85-95
Very High	23-37.5	95-99
Extreme	> 37.5	>99

FPI will be used to assist the BVES Team in making operational decisions regarding the sub-transmission and distribution system. As shown in the table above as FPI increases, the risk of wildfire increases. Therefore, the BVES Team will initiate operational and customer procedures to mitigate wildfire. The FPI is updated at least daily by the Wildfire Mitigation & Reliability Engineer.

As an additional aid and backup to the FPI, the contracted meteorologist integrates the National Fire Danger Rating System (NFDRS) with the detailed local forecast specific to BVES's service area and develops a risk rating as indicated below in Table 4-2: Fuel Dryness and High-Risk Days and Table 4-3: Fire Potential.

Table 4-2: Fuel Dryness and High-Risk Days

Fuel Dryness & High Risk Days	Rating	Description
Green	Moist	Little to no risk of fires.
Yellow	Dry	Low risk of large fires in the absence of a "High Risk" event.
Brown	Very Dry	Low/moderate risk of large fires in the absence of a "High Risk" event.
Orange	High-Risk Day	At least a 20% chance of a "Large Fire" due to a combination of either "Dry" or "Very Dry" fuel dryness and a critical burn environment (e.g., Santa Ana winds).
Red	High-Risk Day	At least a 20% chance of a "Large Fire" due to a combination of either "Dry" or "Very Dry" fuel dryness and an ignition trigger (lightening).

Table 4-3: Fire Potential

The Field Operations Supervisor will monitor the FPI as reported by the Wildfire Mitigation & Reliability Engineering and indications from installed weather stations, which are equipped with alarms based on actual wind speed, and then direct the proper operational pre-planned response. As indicated in Table 4-4 below, "High", "Very High" and "Extreme" FPIs are considered elevated fire threat conditions that require the BVES system to be configured for fire prevention over reliability concerns.

Table 4-4: Operational Direction Based on Fire Potential Index For Overhead Facilities

FPI Category	Very Low and Low	Moderate	High	Very High/Extreme
Auto-Reclosers and Protective Switches with Reclosing Capability	Automatic[1]	Automatic[1]	Manual (Non-Automatic)	Manual (Non-Automatic)
Patrol following circuit or feeder outage	No[2,3]	Yes	Yes	Yes
Fuse TripSavers	Automatic[1]	Automatic[1]	Manual (Non-Automatic)	Manual (Non-Automatic)
Designate which circuits are under: (1) Consideration (2) In Scope	No	No	Yes	Yes
Deploy Wildfire Risk Team(s) to circuits "In Scope".	No	No	Yes[4]	Yes
Cease using any spark-producing tools and equipment for circuits under consideration or in scope.	No	No	Yes	Yes
Cease vegetation management work for circuits under consideration or in scope.	No	No	Yes[5]	Yes
Cease "high risk" energized line work for circuits under consideration or in scope.[6]	No	No	Yes	Yes
Conduct additional patrols in high risk areas as directed by the Field Operations Supervisor and Wildfire Mitigation & Reliability Engineer.	No	No	Yes	Yes
Forward to Field Operations updated list of medical baseline customers and impacts access and functional needs population.	No	Yes	Yes	Yes
Review Local Government, Agencies, First Responders, Critical Infrastructure, and Stakeholder notification lists and procedures.	No	Yes	Yes	Yes
Review customer notification procedures.	No	Yes	Yes	Yes
Activate EOC.	No	No	Yes[7]	Yes
Initiate Local Government, Agencies, First Responders, Critical Infrastructure, and Stakeholder notification in accordance with BVES PSPS Procedures.	No	No	Yes[8]	Yes[8]
Initiate customer notification in accordance with BVES PSPS Procedures.	No	No	Yes[8]	Yes[8]
Prepare Bear Valley Power Plant for sustained operations.	No	No	Yes	Yes
Conduct switching operations to minimize impact of potential PSPS activity	No	No	Yes	Yes
Activate first responder, local government and agency, customer and community, and stakeholders PSPS communications plan.	No	No	Yes[9]	Yes[9]
Activate Community Resource Centers.	No	No	Yes[10]	Yes
Invoke Public Safety Power Shutoff.	No	No	Per Table 4-5 Thresholds[11]	Per Table 4-5 Thresholds[11]

[1] Per Section 4.4.1.
[2] During the non-winter months, when an Auto-Recloser, Switch, or Fuse TripSaver that was placed in "Manual" due to the above policy trips open, the affected portions of the de-energized circuit or feeder will be patrolled prior to re-energizing them. If the cause is likely known and the fire risk is "Very Low" or "Low" the Field Operations Supervisor may authorize the Line Crew to test the device once. If the device trips open again, the circuit or feeder must be thoroughly patrolled to determine the fault and ensure there is no risk to causing fire.
[3]No patrol is required. Re-test allowed following check of fault indicators, SCADA, other system indicators, and reports from the field. If the re-test fails, a patrol is mandatory.
[4]Based on actual conditions in the area, the Field Operations Supervisor may rescind the requirement to deploy Wildfire Risk Teams.
[5]The Wildfire Mitigation & Reliability Engineer may allow certain vegetation management activities to continue with additional controls to mitigate ignitions in place.
[6]The Field Operations Supervisor will review and designate which work is considered "high risk." Examples of "high risk" work include line work that can result in ignitions such as line work in high vegetation density areas where the line could make contact with vegetation or work that could cause line slap.

[7]If forecasted or actual sustained wind or 3-second wind gusts expected to exceed 30 mph and expected to increase. The Utility Manager may reduce the scope of the EOC to match actual conditions in the field.
[8]Executive Management will approve initiating notifications.
[9]Executive Management will approve activating first responder, local government and agency, customer and community, and stakeholders PSPS communications plan.
[10]Based on actual conditions in the area, the Energy Resource Manager may rescind the requirement to activate the Community Resource Center.
[11]If actual sustained wind or 3-second wind gusts exceed thresholds in Table 4-5. The President may initiate PSPS if in his judgement the actual conditions in the field pose a significant safety risk to the public even if the thresholds of Table 4-5 are not exceeded.

Table 4-5 PSPS Thresholds provides wind thresholds (forecasted or actual sustained wind or 3-second wind gusts) to invoke PSPS given circuit type and FPI. For bare conductors, the major concern is BVES "blow-ins". If in the judgement of the Utility Manager, based on observations from the field that "blow-ins" are occurring or very likely even though the thresholds in Table 4-5 have not been exceeded, a BVES PSPS should be invoked.

Table 4-5: PSPS Thresholds

FPI	High	Very High/Extreme
Bare Conductor Circuit	40	35
Bare Conductor Circuit with EPSS Enabled	50	45
Covered Conductor Circuit	65	65

When sub-transmission and distribution facilities are in areas where the FPI is designated as "High" or higher, the circuit is designated as being under "consideration". When facilities are designated as being under "consideration," the Management and the Operations Team will evaluate the facilities for their condition (material condition, level of grid hardening, level of protective equipment and automation, etc.), status (energized, loading, etc.), scheduled work and maintenance, status of situational awareness monitoring equipment, actual weather, other weather forecasts, staff resources, etc. The Customer Service Team will review notification procedures for the affects area(s).

When sub-transmission and distribution facilities are in areas where the FPI is designated as "Very High" or higher, the circuit is designated as being under "in scope". When facilities are designated as being "in scope," all of the actions required for circuits "under consideration" will be taken. Additionally, the BVES Team will start making preparations for possible PSPS implementation on BVES affected circuits.

Public Safety Power Shutoff (PSPS) Activation Consideration. BVES determined that specific actions per Table 4-4 above should be taken when wind gusts of 3 seconds or more exceed 55 mph and a period of high fire threat danger exists. These conditions are often referred to as "extreme fire threat weather and conditions."

4.4.3. Despite having a proactive and aggressive vegetation management program, vegetation may still contact power lines; for example, in high winds, branches outside the vegetation clearance zone may break and be blown onto bare conductors, and/or trees outside the clearance zone may fall into bare conductors. The specific strength of trees and branches is unknown; therefore, in high winds, it is impossible to predict how every tree and branch in the service territory would be impacted. This condition plays a key role in how BVES has selected its tripwire 3-second wind gust speed for a BVES PSPS and designated certain locations as “at risk” locations for proactive de-energization during extreme fire weather conditions.

4.4.4. Changes in vegetation density, circuit improvements such as covering bare wire, or other environmental factors may drive BVES to re-evaluate the designated “at risk” line sections in its system and, therefore, specific line sections may be added, removed or modified to the “at risk” list as appropriate in the future.

4.4.5. Because BVES is not able to determine the strength or health of vegetation surrounding bare conductors outside of the required vegetation clearance zones, as well as other structures that may come loose and impact BVES distribution facilities. Therefore, BVES may determine a need to proactively de-energize facilities during high fire threat and high wind conditions. This would be done in close consultation and coordination with local government and agencies.

4.4.6. In determining whether to invoke PSPS, BVES staff considers factors driving “extreme fire weather” and dangerous threat conditions including, but not limited to, the following:

- Design, strength, and other characteristics of distribution overhead facilities.
- Vegetation density.
- FPI.
- High winds.
- Low humidity.
- National Weather Service advisories.
- Local weather forecasts and advisories.
- BVES meteorologist’s forecast.
- Observed conditions.
- Information from BVES-installed weather stations.
- Real-time information from trained personnel positioned in high-risk areas.
- Input from state and local authorities and Emergency Management Personnel.
- Fire threat to electric infrastructure.
- Public Safety Risk.

“Extreme fire weather conditions” are deemed to be forecasted or exist when the FPI is High, Very High, or Extreme, high winds (45 mph or greater) are forecasted or measured, and the BVES meteorologist forecasts high fire threat conditions.

If "extreme fire weather conditions" are forecasted or exist, BVES Staff will implement BVES Public Safety Power Shutoff Procedures at the direction of the President.

4.5.5 BVES has identified seven sections of "at risk" areas based on the type of distribution facilities (overhead bare conductions, high voltage, etc.), tree and vegetation density, available dry fuel, and other factors. These "at risk" areas are identified on the map in Appendix A. These areas may be selectively de-energized by "opening" the ARs designated in Table 4-6, Switches to De-energize "At Risk" Areas, below.

Table 4-6: Switches to De-energize "At Risk" Areas

Circuit (At Risk Area)	Circuit Breaker
North Shore 4kV (Fawnskin Area)	AR 805
North Shore 4kV	North Shore CB
Pioneer 4kV (Baldwin Lake Area)	AR 1302
Boulder 4kV (Boulder Bay Area)	AR 105
Holcomb 4kV	Holcomb CB

BVES expects that if a BVES PSPS is necessary, it should be limited to one or more of these "at-risk" areas. However, the Operations Team must monitor the entire service area and invoke PSPS as a measure of last resort on any BVES circuit when conditions warrant such action.

4.5. Restoration from PSPS. When wind speeds in the affected area where PSPS was invoked calm below 50 mph for a minimum period of 20 minutes, crews may assess if the fire weather conditions have subsided to "safe levels" to begin the restoration of de-energized circuits. However, the crews may extend the calm period beyond 20 minutes, if they determine further gusts of greater than 50 mph are likely based on their direct observation of local conditions or forecasts indicate a high probability of winds picking up to greater than 50 mph. Crews should communicate with the Field Operations Supervisor prior to assessing the situation as "safe levels" so that an evaluation of actual conditions in the field may be merged with the latest forecasted information. Restoration activities include:

- Validating that the extreme fire weather conditions have subsided to safe levels.
- Conducting field inspections and patrols of facilities that were de-energized.
- Repair of any identified immediate hazards (Level 1 inspection conditions)
- Re-energization of inspected circuits.

5. BVES PSPS Procedures

5.1. Emergency Disaster and Response Plan. Section 4 of the BVES Emergency Response and Disaster Plan (EDRP) explains the BVES system sources of power and actions to be taken when there is partial or complete loss of sources of power. Appendix B to the EDRP provides a graphic showing the sources of power available to the BVES system including the SCE supply lines and their capacity. This PSPS Plan provides supplemental guidance in the case of an SCE PSPS event leading to a complete or partial loss of all SCE lines in order to avoid a "black start" of the Bear Valley Power Plant (BVPP). Once a BVES PSPS is implemented, outages shall be managed using the guidance of the BVES EDRP and the supplemental guidance of this procedure.

5.2. PSPS Phases. In ***Table 5-1, PSPS Phases for PSPS Procedures***, BVES provides a time-line summary of actions to be taken for PSPS on BVES-owned bare wire overhead power lines affecting some or all of the BVES service area or a SCE-directed PSPS affecting the BVES service area.

It should be noted that weather changes can be sudden and the target timelines may end up being shorter than indicated in Table 5-1. PSPS actions are driven by forecasts and actual conditions in the field. The specific phases are:

- **Preparatory Phase:** Conducted annually well before extreme fire threat conditions are expected; or when lessons learned or other conditions warrant updating plans, training, or outreach. This involves the developing of communication and notification plans jointly with stakeholders such as CalOES, county and local governments, independent living centers, and representatives of people/communities with AFN. Review and revise plans for establishing CRC(s). BVES currently holds PSPS exercises to further develop their staff to be readily available to properly activate a PSPS event. For further detail regarding BVES Functional Exercise: Bear Valley Wildfire Threat Situation Manual in Appendix F.
- **Warning Phase:** Approximately 4-7 days prior to forecasted extreme fire threat weather and conditions, the warning phase involves assessing whether activating a PSPS may be warranted. If a PSPS is possible or likely, BVES notifies local government, agencies, partner organizations, and customers. This phase includes various levels of notification at the 4-7 days ahead, 4 days ahead, 2-3 days ahead, 1-2 days ahead, and 1-4 hours ahead (PSPS imminent) points in the preparatory process.
- **Implementation Phase:** De-energization actions are taken for "at-risk" areas due to observed extreme fire threat weather and conditions or imminent or active SCE-directed PSPS of SCE supply lines to BVES service area.
- **Restoration Phase:** This phase enables the safe restoration of power to de-energized circuits following verification that actual extreme fire threat weather and conditions have subsided and/or restoring SCE supply lines when they are re-energized. All de-energized lines must be patrol-inspected for vegetation and equipment hazards and all Level 1 conditions must be remediated before restoring power.
- **Reporting and Lessons Learned Phase:** Documenting and reporting to Safety Enforcement Division required information on the PSPS event and capturing lessons

learned to ensure future PSPS events benefit from an understanding of what worked and what did not work in previous PSPS events.

5.3. PSPS Exercises. BVES conducts at least one tabletop and one functional simulation exercise annually. These exercises involve participating stakeholders from the Big Bear community and are coordinated with CPUC Cal Fire, Cal OES, communication providers, AFN representatives, and other public safety partners. Additionally, BVES will coordinate with these stakeholders to develop and plan the exercises. The exercises seek to prepare BVES and its community partners for a PSPS event, and enhance their performance, communication protocols, notification practices, and restoration procedures, and test the functionality of the plan to the extent practicable.

BVES will keep detailed records of these plans and submit reports of these exercises to the CPUC as required. BVES will review the exercises to identify strengths and weaknesses of BVES actions and seek to incorporate lessons learned into this Plan and other associated documentation, as appropriate.

5.3.1. Incorporating Lessons Learned from PSPS Exercises. BVES is committed to continuous improvement in its PSPS planning and execution. Following each PSPS exercise or actual PSPS event, BVES systematically reviews its response and identifies key takeaways, which are used to refine its operational plans.

- This process includes: Carrying out internal After-Action Reviews (AAR) planning discussion with structured debriefs with teams for insight gathering and reflection after exercises;
- Developing corrective action initiatives for short- and long-term improvements to improve PSPS plans and procedures;
- Conduct annual training for internal teams and external stakeholders; and
- Incorporate feedback and insights into annual PSPS Plan updates, ensuring adaptive and continuous improvement.

5.3.2. Record-Keeping for PSPS Events and Simulations. BVES maintains comprehensive records of BVES PSPS-related activities to ensure compliance with CPUC reporting requirements and support continuous improvement. The key elements of BVES' PSPS documentation process include:

- Insights from PSPS exercises are gathered through post-simulation surveys and review sessions with stakeholders and participants. This ensures that feedback is captured while experiences are fresh and can be integrated into future planning;
- Detailed documentation of BVES PSPS events, including all required reports submitted to the CPUC SED, capturing event triggers, affected areas, notification timelines, and customer outreach efforts;
- Documentation of all notifications sent during BVES PSPS events, including messaging, Public Safety Partner engagement and records with timestamps and

verification of compliance with regulatory communication requirements as applicable;

- Internal records tracking decision-making processes during BVES PSPS events, including activation rationale, weather conditions, grid status, and any significant operational adjustments that impact the event's execution; and
- Records adhering to CPUC de-energization guidelines and mitigation requirements, which are securely stored within BVES's internal systems and supplemented by external cloud-based resources managed through consulting contractors.

<table>
<tr><th colspan="4">Table 5-1: PSPS Phases for PSPS Procedures</th></tr>
<tr><th>Phase</th><th>Timeframe</th><th>Internal Staff Actions</th><th>External Communications and Notifications</th></tr>
<tr><td>Preparatory</td><td>Pre-fire season.
Conducted annually well before extreme fire threat conditions are expected; or
When lessons learned or other conditions warrant updating plans, training, and/or outreach.</td><td>Planning and Training
Managers review and update plans and procedures.
Managers ensure staff are trained on PSPS procedures as applicable.
Reach out to media and community-based organizations to ensure consistent awareness of and availability to third parties of all messaging and map data, including application programming interfaces that are used for de-energization events.
Customer Service Department will ensure all equipment and supplies for the CRC are functional and readily available.
Coordinate with stakeholders including CPUC, CalFire, CalOES, communications providers, representatives of people/communities with access and functional needs, and other public safety partners to plan de-energization simulation exercises throughout the utility service territories in the areas with the highest historical and forecasted risk for de-energization in advance of fire season.</td><td>Local Government, Agencies, and Partner Organizations:
Provide copy of plan and solicit comments.
Incorporate comments as deemed appropriate.
Conduct meetings to discuss procedures.
Update primary and secondary contacts for PSPS communications.
Advisory Board: May consist of public safety partners, communications and water service providers, local and tribal government officials, business groups, non-profits, representatives of people/communities with access and functional needs and vulnerable communities, and academic organizations.
Customer Outreach and Education:
Post PSPS information and list of PSPS POCs on BVES's website and social media.
Include PSPS information in periodic customer newsletter.
Conduct public workshops.
Provide PSPS notifications via email, telephone calls, Interactive Voice Response (IVR) proactive calling system, and two-way text messaging.</td></tr>
<tr><td>Warning</td><td>4-7 Days Ahead
When forecasts indicate extreme fire threat weather and conditions may occur</td><td>Operations & Planning:
Evaluate system for possible impact area(s) and ensure resources ready to support PSPS.
Contact SCE Staff and closely follow status of SCE supply lines (Doble, Cushenberry, and Bear Valley/Radford).
Review operational and maintenance status of sub-transmission system.
Review operational and maintenance status of Bear Valley Power Plant (BVPP).
Review operational and maintenance status of Radford Line.
Consider conducting patrol of Radford Line.
Review FPI, WFA-E, National Weather Service (NWS) forecasts, National Fire Danger Rating System (NFDRS) 7-day forecast, and weather and threat assessments from contracted meteorology consultant.
Notify meteorology consultant to provide more frequent forecasts.
Alert customer service to possibility of PSPS.
Customer Service:</td><td>None</td></tr>
</table>

		• Review and edit as applicable templates for PSPS events and the anticipated impacts on BVES Customers. • Staff drafts notices to Public Affairs consultant for review, significant changes to templates are made. • Create warning notifications to customers via email, telephone calls, IVR proactive calling system, and two-way text messaging.	
Warning	**4 Days Ahead** If continuing and consistent forecasts of extreme fire threat weather and conditions	**Operations & Planning:** • Closely monitor fire weather alerts from various sources with the goal of refining the forecast (FPI, WFA-E, NWS, NFDRS, and meteorology consultant weather and threat assessments). • Continue contacts with SCE Staff and closely follow status of SCE supply lines. If any SCE lines are under "PSPS Consideration," take actions per Table 4-2, BVES Action for SCE Lines Under PSPS Consideration. • Ensure sub-transmission system is in most reliable condition. Defer or secure from planned maintenance. • Ensure BVPP ready to operate. Defer or secure from planned maintenance. • Alert Energy Resource Department of possible extended BVPP operations. • Consider energizing Radford Line, if deemed necessary for reliability. • Closely coordinate with SCE Staff regarding the PSPS status of SCE supply lines. • Ensure BVES-installed weather stations fully operational. • Ensure circuit load monitoring equipment fully operational. • Place BVES staff incident responders on alert. **Customer Service:** • Finalize **"4 Day Alert"** email regarding continuing and consistent forecasted extreme fire threat weather and conditions, which may lead to possible BVES directed PSPS and/or SCE directed PSPS. - provide anticipated impacts on BVES Customers and direction of event. - Obtain President's approval to release. • Issue a press release to local media (newspaper and radio) and post notification on website. • Create warning notifications to customers via email, telephone calls, (IVR) proactive calling system, and two-way text messaging.	**Local Government, Agencies, and Partner Organizations:** • Email **"4 Day Alert"** to local government, agencies, and partner organizations' primary and secondary points of contact. • Alert the emergency management community, first responders, and local government first.

Warning	**2-3 Days Ahead** Extreme fire threat weather and conditions forecasted with increasing confidence	**Operations & Planning:** • Continue to closely monitor fire weather alerts. • Prepare staff rotation plans to support continuous field crew operations, BVPP operations, dispatch, and customer service. • Evaluate need for additional resources from mutual aid agreements (CUEA and MMAA) and contracted services. Alert additional resources points of contact. • Set up processes to frequently monitor BVES-installed weather stations. • Review pre-approved field Switching Orders against current system line-up and make changes as applicable with Field Operations Supervisor's approval. • Keep Customer Service informed of latest forecast to ensure accurate communications with stakeholders. • Closely coordinate with SCE Staff regarding SCE supply lines to the BVES service area and take actions per Table 4-2, BVES Action for SCE Lines Under PSPS Watch, as applicable. **Customer Service:** • Finalize **"2-3-Day Notice"** regarding forecasted extreme fire threat weather and conditions, about possible BVES directed PSPS and/or SCE directed PSPS. - Provide anticipated impacts on BVES Customers and direction of event. - Obtain President's approval to release. • Issue a press release to local media (newspaper and radio) and post notification on website. • Create warning notifications to customers via email, telephone calls, (IVR) proactive calling system, and two-way text messaging.	**Local Government, Agencies, and Partner Organizations:** • Email **"2-3 Day Notice"** to local government, agencies, and partner organizations' primary and secondary points of contact. • Coordinate with the emergency management community, first responders, and local government first. • Encourage widest dissemination of this information. **Customer Outreach:** • Post **"2-3 Day Notice"** on BVES website and social media. • Issue **"2-3 Day Notice"** press release for local media. • Send out **"2-3 Day Notice"** via IVR. • Send out **"2-3 Day Notice**" via Text • Send out **"2-3 day Notice"** via Email
Warning	**1-2 Days Ahead** Extreme fire threat weather and conditions forecasted with high degree of confidence	**Operations & Planning:** • Continue to closely monitor fire weather alerts and observed conditions from various sources with the goal of refining the forecast. • If needed, request additional resources from mutual aid agreements (CUEA and MMAA) and contracted services). • Keep Customer Service informed of latest forecast to ensure accurate communications with stakeholders. ○ Set up CRC and conduct a mock SOE scenario to include testing of all equipment and needed supplies.	**Local Government, Agencies, and Partner Organizations:** • Email **"1-2 Day Notice"** to local government, agencies, and partner organizations' primary and secondary points of contact. • Coordinate with the emergency management community, first responders, and local government first. • Encourage widest dissemination of this information. **Customer Outreach:** • Post **"1-2 Day Notice"** on BVES website and social media. • Issue **"1-2 Day Notice"** press release for local media.

		○ Purchase non-perishable food items to provide to our customers including bottled water. • Continue to closely coordinate with SCE Staff regarding SCE supply lines to the BVES service area and take actions per Table 4-2, BVES Action for SCE Lines Under PSPS Watch, as applicable. • When directed by the Utility Manager: ○ Staff incident responders called in. ○ Incident dispatch established. ○ Field Crews dispatched to monitor various actual field conditions for extreme fire weather and other dangerous conditions throughout the service area and “at risk” areas. ○ Implement BVES EDRP including staffing the EOC as applicable. **Customer Service:** • Finalize **“1-2 Day Notice”** regarding imminent extreme fire threat weather and conditions, which may result in BVES directed PSPS and/or SCE directed PSPS. - Provide anticipated impacts on BVES Customers and duration of event. - Obtain President’s approval to release. • Identify medical baseline and AFN customers that may lose power as result of PSPS. • Issue a press release to local media (newspaper and radio) and post notification on website. • Issue warning notifications to customers via email, telephone calls, (IVR) proactive calling system, and two-way text messaging	• Send out **“1-2 Day Notice”** via IVR. • Send out “1-2 Day Notice” via Text • Activate “1-2 day Notice” via Email
Warning	**1-4 Hours Ahead When De-Energization Imminent.** Extreme fire threat weather and conditions validated by field resources	**Operations & Planning:** • Closely coordinate with SCE regarding SCE-directed PSPS affecting SCE supply lines into BVES service area and take applicable actions per Table 4-3, BVES Action for SCE Lines De-energized Due to PSPS. • Frequently monitor BVES-installed weather stations. • Patrol throughout service area especially “at risk” areas to monitor various actual field conditions for extreme fire weather and other dangerous conditions. • Monitor local wind gusts in “at-risk” areas. **Customer Service:**	**Local Government, Agencies, and Partner Organizations:** • Email **“De-energization Imminent Notice”** to local government, agencies, and partner organizations. • Coordinate with the emergency management community, first responders, and local government in managing outages due to PSPS. • Provide list of customers that may be without power and listed as medical baseline customers to Sheriff Department and Fire Department. **Customer Outreach:**

		• Finalize "**De-energization Imminent Notice"** regarding imminent PSPS de-energization(s) directed by BVES or SCE - Include areas to be de-energized, number of customers without power, and best estimated time to restore (ETR). - Obtain President's approval to release. • Identify medical baseline customers that may lose power. • Identify AFN customers that may lose power as result of PSPS • Issue a press release to local media and post notification on website. • Issue warning notifications to customers via email, telephone calls, (IVR) proactive calling system, and two-way text messaging.	• Post "**De-energization Imminent Notice"** on BVES website and social media. • Issue "**De-energization Imminent Notice"** press releases for local media. • Send "**De-energization Imminent Notice"** via IVR. • Send "**De-energization Imminent Notice** Day Notice" via Text • Send "**De-energization Imminent Notice**" via Email
Implementation	**During de-energization event.** A PSPS event is initiated.	**Operations & Planning:** • Closely coordinate with SCE regarding SCE-directed PSPS affecting SCE supply lines into BVES service area and take applicable actions per Table 4-3, BVES Action for SCE Lines De-energized Due to PSPS. • Frequently monitor BVES-installed weather stations. • Patrol throughout service area especially "at risk" areas to monitor field conditions for extreme fire weather and dangerous conditions. • Monitor local wind gusts. • De-energize circuits in "at risk" areas as wind gusts reach threshold for de-energization as designated by Field Operations Supervisor. • Field Crews may de-energize additional power lines they evaluate as posing a public safety hazard or as directed by Field Operations Supervisor. • Prepare GO-166 major outage and ESRB-8 notifications as applicable. **Customer Service:** • Finalize "**De-energization Notice"** regarding extreme fire threat conditions and actual PSPS de-energization(s) directed by BVES and/or SCE. Must include: - areas de-energized, - number of customers without power, and best estimated time to restore (ETR). Obtain President's approval to release. • Issue **"De-energization Updates"** providing status changes such as when the number of customers without	**Local Government, Agencies, and Partner Organizations:** • Email **"De-energization Notice"** to local government, agencies, and partner organizations. • Coordinate with the emergency management community, first responders, and local government in managing outages due to PSPS. • Send **"De-energization Updates"** on the PSPS. • Provide list of customers without power and listed as medical baseline and AFN customers to Sheriff Department and Fire Department. • Encourage widest dissemination of this information. • Notify California Public Utilities Commission (CPUC) and Warning Center at the Office of Emergency Services San Bernardino within one hour of shutting off the power if the outage meets the major outage criteria of GO-166. • Notify President Safety Enforcement Division (SED), CPUC within twelve hours of the power being shut off per ESRB-8. **Customer Outreach:** • Post "**De-energization Notice"** and "**De-energization Updates"** (when warranted) on BVES website and social media. • Issue "**De-energization Notice"** and "**De-energization Updates"** (when warranted) press releases for local media. • Send "**De-energization Notice"** and "**De-energization Updates"** (when warranted) via IVR. • Send "De-energization Notice" and "**De-energization Updates"** (when warranted) via Text

		power or ETR(s) change significantly. Obtain President's approval to release. • Identify lists of medical baseline customers without power. • Issue a press release to local media (newspaper and radio) and post notification on website. • Issue warning notifications to customers via email, telephone calls, (IVR) proactive calling system, and two-way text messaging.	• Activate "De-energization Notice" and "**De-energization Updates"** (when warranted) via Email • Communicate with emergency services regarding AFN and medical baseline customers.
Restoration	**Re-energization** Extreme fire conditions subside to safe levels as validated by field conditions	**Operations & Planning:** • Validate extreme fire weather conditions have subsided to safe levels as designated by the Field Operations Supervisor and report these conditions to Dispatch. • Conduct and patrols of de-energized facilities. • Restore power to affected circuits following satisfactory completion of field inspections and patrols. • Conduct switching operations as directed by Field Operations Supervisor to restore systems normal as SCE restores supply lines, as applicable. **Customer Service:** • Finalize **"Intent to Restore"** notice to include ETRs and obtain President's approval to release. • Finalize **"Restoration Complete"** notice to be issued when power is fully restored and obtain President's approval to release. • Breakdown of CRC including removal/storage of all equipment and supplies.	**Local Government, Agencies, and Partner Organizations:** • Send **"Intent to Restore"** notice to local government, agencies, and partner organizations. Encourage widest dissemination of this information. • Coordinate with the emergency management community, first responders, and local government in managing restorations. • Send **"Restoration Complete"** notice to local government, agencies, and partner organizations once power is fully restored or an update if restoration is delayed. **Customer Outreach:** • Post **"Intent to Restore"** notice on BVES website and social media. • Issue **"Intent to Restore"** press release for local media. • Send **"Intent to Restore"** notice via IVR. • Send **"Intent to Restore"** notice via Text • Send **"Intent to Restore"** notice via Email • Post **"Restoration Complete"** notice on BVES website and social media once power is fully restored or an update if restoration is delayed. • Issue **"Restoration Complete"** press release for local media once power is fully restored or an update if restoration is delayed. • Send **"Restoration Complete"** notice via IVR once power is fully restored or an update if restoration is delayed. • Send **"Restoration Complete"** notice via Text once power is fully restored or an update if restoration is delayed. • Send **"Restoration Complete"** notice via Email once power is fully restored or an update if restoration is delayed.
Reporting and Lessons Learned	**Post Event**	**Operations & Planning:** • Conduct lessons learned with applicable staff. Utility Manager will include Customer Service and solicit input	**CPUC Safety Enforcement Division:** • File a report (written) to President of SED no later than 10 business days after the Shutoff event ends per ESRB-8.

		from Local Government, Agencies, and Partner Organizations. • Update plan and procedures per the lessons learned, if necessary. • Prepare PSPS Post Event Report required by ESRB-8 and forward to President and Manager of Regulatory Affairs for approval.	

5.4. SCE-Directed PSPS Procedures. Close coordination with SCE is essential to mitigating the impact of any SCE directed PSPS event that would result in a complete or partial loss of SCE supply lines that feed power to the Big Bear Valley. The following preparatory coordination steps are established:

- Each year, before fire season, BVES Management Team engages SCE Management on coordination for potential and actual PSPS events.
- BVES Management Team updates contact information with the SCE Key Account Manager for the BVES account, upon any change.
- BVES Field Operations staff updates contact information with the SCE Lugo and Colton Control Stations which have direct operational control over the SCE supply lines to BVES.

When SCE PSPS events are forecasted, the SCE Key Account Manager will coordinate with BVES Management and the SCE Lugo and Colton Control Stations will coordinate directly with the designated BVES Field Operations Team until the event is complete or canceled.

Table 5-2 outlines recommended actions for BVES to address general outages, including considerations for SCE PSPS events, to effectively prepare the BVES system for a full or partial loss of SCE supply lines.

Table 5-2: BVES Action for SCE Lines Under PSPS Consideration

Condition	BVES Action
SCE places Doble or Cushenberry Line under PSPS Consideration.	1. Notify key internal staff and brief Field Operations staff on condition for situational awareness. 2. Operations & Planning Manager evaluates energizing Radford Line for improved reliability.
SCE places Bear Valley Line under PSPS Consideration.	1. Notify key internal staff and brief Field Operations staff on conditions for situational awareness. 2. If Radford is energized, shift loads to Shay Line.
SCE places Doble **and** Cushenberry Lines under PSPS Consideration.	1. Notify key internal staff and brief Field Operations staff on condition for situational awareness. 2. Energize the Radford Line. 3. Prepare for potentially losing all SCE supply lines from Lucerne. 4. Prepare for sustained BVPP operations and rolling blackouts. 5. Evaluate distribution circuit loads.
SCE places Doble or Cushenberry, and Bear Valley Lines under PSPS Consideration	1. Notify key internal staff and brief Field Operations staff on condition for situational awareness. 2. Prepare for potentially losing all SCE supply lines from Lucerne. 3. Prepare for sustained BVPP operations and rolling blackouts. 4. Evaluate distribution circuit loads.
SCE places Doble, Cushenberry, and Bear Valley Lines under PSPS Consideration	1. Notify key internal staff and brief Field Operations staff on condition for situational awareness. 2. Prepare for potentially losing all SCE supply lines into BVES service area. 3. Prepare for sustained BVPP operations and rolling blackouts. 4. Evaluate distribution circuit loads.

Table 5-3, BVES Action for SCE Lines De-energized Due to PSPS, provides procedures to use in the event of a partial or complete loss of SCE supply lines. These procedures are based on procedures in the BVES EDRP and take into account that BVES will closely coordinate with SCE Staff as follows:

- SCE should provide warnings of impending PSPS on the SCE lines about 2 days prior to the event.
- SCE should provide updates to the status of the lines under PSPS consideration.
- SCE should notify BVES at least 4 hours prior to de-energizing any SCE supply lines to BVES service area.

These timely notifications will allow BVES to take preparatory action to shed load to within the expected capacity of its remaining sources of power and allow BVES to avoid a “blackstart” on the BVPP. Therefore, the procedures of Table 5-3 should be followed during PSPS event. However, if there is a sudden complete or partial loss of SCE supply lines, the procedures in Section 4 of the BVES EDRP are more appropriate and should be followed as directed by the Utility Manager.

Table 5-3: BVES Action for SCE Lines De-energized Due to PSPS	
Condition	**BVES Action**
SCE De-energizes Doble or Cushenberry Line for PSPS.	1. Notify key staff and brief Field Operations staff on condition for situational awareness. 2. Energize Radford Line if needed to meet load demand and reliability. 3. Start up the BVPP as needed to meet load demand. 4. No reduction in load necessary, since the Doble and Cushenberry are capable of carrying the other's load. 5. Implement BVES EDRPn for a partial loss of SCE supply lines.
SCE De-energizes Bear Valley Line for PSPS.	1. Notify key staff and brief Field Operations staff on condition for situational awareness. 2. If Radford is energized, shift loads to Shay Line prior to de-energizing for PSPS. This should be done about 4 hours prior to the SCE de-energizing the line. 3. If needed, start up the BVPP to meet load demand. 4. If needed, instruct interruptible customers (Bear Mountain Resorts) to reduce load as needed to meet load demand. 5. Implement BVES EDRP for a partial loss of SCE supply lines.
SCE De-energizes Doble or Cushenberry **and** Bear Valley Lines for PSPS.	1. Notify key staff and brief Field Operations staff on condition for situational awareness. 2. Since the Doble and Cushenberry are capable of carrying the other's load, follow the procedure for "SCE De-energizes Bear Valley Line for PSPS" above. 3. Prepare for potentially losing all SCE supply lines into BVES service area. 4. Prepare for sustained BVPP operations and rolling blackouts. 5. Evaluate distribution circuit loads. 6. Implement BVES EDRP for a partial loss of SCE supply lines.
SCE De-energizes Doble **and** Cushenberry Lines for PSPS.	1. Notify key staff and brief Field Operations staff on condition for situational awareness. 2. Energize the Radford Line. 3. Four hours prior to SCE de-energizing the lines, per the Field Operations Supervisor's direction, shift as much of the load to the BVPP and Radford Line as follows: a. Open the Shay and Baldwin ARs. b. "Express" the Radford Line to Meadow Substation without overloading the Radford Line per Field Operations' switching order. c. Start BVPP, place enginators online, and increase load to within the combined capacity of the BVPP and Radford Line. d. Implement BVES EDRP for sustained loss of SCE supplies from Lucerne including "rolling blackout" procedures. 4. Prepare for sustained BVPP operations and rolling blackouts. 5. Frequently monitor distribution circuit loads.

Table 5-3: BVES Action for SCE Lines De-energized Due to PSPS	
Condition	**BVES Action**
SCE de-energizes Doble, Cushenberry, **and** Bear Valley Lines for PSPS.	1. Notify key staff and brief Field Operations staff on condition for situational awareness. 2. If the Radford Line is energized, shift loads to the Shay Line. 3. Four hours prior to SCE de-energizing the lines, per the Field Operations Supervisor's direction, perform the following: a. Start up all BVPP enginators. b. Reduce system load to within the capacity of the BVPP by isolating distribution circuits as directed by the Field Operations Supervisor. c. Once system load is matched with the BVPP capacity, open the Shay and Baldwin ARs. d. Implement BVES EDRP for sustained loss of all SCE supply lines including "rolling blackout" procedures.

6. PSPS Public Outreach and Communications

6.1. Importance of Public Outreach. Due to the significant impact a PSPS event may have on the community and customers, early and accurate communications must be conducted throughout the BVES PSPS event in coordination with local government, agencies, partner organizations (including emergency management community and first responders, CalOES, local governments, independent living centers, and representatives of people/communities with AFN), and customers. Effective communications are key to allowing stakeholders to take preparatory actions to mitigate the impact of a BVES PSPS event. It is also understood the importance of hosting community workshops to allow for community members to understand the process leading to a PSPS event. BVES hosts exercises and workshops with the community to better prepare customers for a BVES PSPS event. BVES also conducts public safety briefings with the CPUC related to de-energization events, including exercises.

BVES retains ultimate responsibility for notification and communication throughout a BVES PSPS event.

6.2. EDRP Communications Procedures. During the period leading up to the BVES PSPS event, during a BVES PSPS event, and during the restoration period from a PSPS event, the Emergency Response Communications Plan of the EDRP shall be implemented as applicable in conjunction with this plan.

To accomplish this, BVES shall:

- Develop and use a common nomenclature that integrates with existing state and local emergency response communication messaging and outreach and is aligned with the California Alert and Warning Guidelines.
- Develop multimodal notification and communication protocols and systems to reach customers no matter where the customer is located and deliver messaging in a clear and understandable manner.
- Communicate to customers in different languages and in a way that addresses different access and functional needs using multiple modes/channels of communication.
- Establish a Community Resource Center and work with local organizations to promote community safety (see Appendix C Community Resource Center Protocol).

6.3. PSPS Planned Communications. Table 6-1, BVES PSPS Communications Template Listing, is to be prepared by the Customer Program Specialist and preapproved by the President ahead of an expected BVES PSPS event such to allow BVES staff to quickly initiate effective communications with stakeholders during a BVES PSPS event. The templates are designed to provide a standard “fill in the blank” notice that may be amended depending on the specific situation as applicable. Templates shall initially be reviewed and edited as applicable by BVES’s public relations contractor. Additionally, the templates shall be reviewed annually and/or when lessons learned indicate changes to the templates are appropriate.

Table 6-1: BVES PSPS Communications Template Listing

Template	Content	Media	Recipients
4-Day Alert	Provides notice of continuing and consistent forecasted extreme fire threat weather and conditions, which may lead to possible BVES-directed or SCE-directed PSPS. Also, provides anticipated impacts on BVES customers and direction of event.	• Email	• Local Government, Agencies, and Partner Organizations (Includes emergency management community and first responders, CALOES, county and local governments, independent living centers, and representatives of people/communities with access and function needs), and customers (including medical baseline and behind-the-meter).
2-3 Day Notice	Provides notice of forecasted extreme fire threat weather and conditions, which may lead to BVES-directed or SCE-directed PSPS. Provides anticipated impacts on BVES customers and duration of event.	• Email • BVES Website • Social Media • Press Release • IVR Message • Text Message	• Local Government, Agencies, and Partner Organizations (Includes emergency management community and first responders, CALOES, county and local governments, independent living centers, and representatives of people/communities with access and function needs) and customers (including medical baseline and behind-the-meter).
1-2 Day Notice	Provides notice regarding imminent extreme fire threat weather and conditions, which may result in BVES-directed or SCE-directed PSPS. Also, provides anticipated impacts on BVES Customers and duration of event.	• Email • BVES Website • Social Media • Press Release • IVR Message • Text Message	• Local Government, Agencies, and Partner Organizations (Includes emergency management community and first responders, CALOES, county and local governments, independent living centers, and representatives of people/communities with access and function needs) and customers (including medical baseline and behind-the-meter).

Table 6-1: BVES PSPS Communications Template Listing			
Template	**Content**	**Media**	**Recipients**
De-energization Imminent Notice	Provides notice that BVES-directed or SCE-directed PSPS is imminent (within 1-4 hours) based on extreme fire threat weather and conditions. Also, provides anticipated impacts on BVES customers and duration of event.	• Email • BVES Website • Social Media • Press Release • IVR Message • Text Message	• Local Government, Agencies, and Partner Organizations (Includes emergency management community and first responders, CALOES, county and local governments, independent living centers, and representatives of people/communities with access and function needs) and customers (including medical baseline and behind-the-meter).
De-energization Notice	Provides notice of extreme fire threat weather and conditions and PSPS de-energization(s) and includes areas de-energized, number of customers without power, and best estimated time to restore (ETR).	• Email • BVES Website • Social Media • Press Release • IVR Message • Text Message	• Local Government, Agencies, and Partner Organizations (Includes emergency management community and first responders, CALOES, county and local governments, independent living centers, and representatives of people/communities with access and function needs) and customers (including medical baseline and behind-the-meter).
De-energization Updates	During de-energization event, provides notice of changes such as when the number of customers without power or ETR changes significantly.	• Email • BVES Website • Social Media • Press Release • IVR Message • Text Message	• Local Government, Agencies, and Partner Organizations (Includes emergency management community and first responders, CALOES, county and local governments, independent living centers, and representatives of people/communities with access and function needs) and customers (including medical baseline and behind-the-meter).

Table 6-1: BVES PSPS Communications Template Listing

Template	Content	Media	Recipients
Intent to Restore	Provides notice that extreme fire threat weather and conditions have subsided, BVES crews are performing post-PSPS restoration inspections, and ETR.	• Email • BVES Website • Social Media • Press Release • IVR Message • Text Message	• Local Government, Agencies, and Partner Organizations (Includes emergency management community and first responders, CALOES, county and local governments, independent living centers, and representatives of people/communities with access and function needs) and customers (including medical baseline and behind-the-meter).
Restoration Complete	Provides notice that power is fully restored.	• Email • BVES Website • Social Media • Press Release • IVR Message • Text Message	• Local Government, Agencies, and Partner Organizations (Includes emergency management community and first responders, CALOES, county and local governments, independent living centers, and representatives of people/communities with access and function needs) and customers (including medical baseline and behind-the-meter).

6.4. Critical Facilities and Infrastructure. The terms ‘critical facilities’ and ‘critical infrastructure’ refer to facilities and infrastructure essential to public safety and that require additional consideration for resiliency during PSPS events.[1] The following provides guidance on what constitutes critical facilities and infrastructure:

6.4.1. Emergency Services Sector[2]

- Police Stations
- Fire Stations
- Emergency Operations Centers

6.4.2. Government Facilities Sector

[1] The identification of critical facilities and infrastructure, as well as coordination with key partners during PSPS activations, is guided by multiple sources. Specifically, CPUC D. 21-06-034 (Phase 3), D. 20-05-051 (Phase 2), D. 19-05-042 (Phase 1), and CPUC Resolution ESRB-8 establish the framework for notification, mitigation, and operational transparency related to PSPS events.

[2] BVES does not currently serve any federally recognized Tribal Nations or Tribal lands within its service territory. However, BVES acknowledges the importance of Tribal governments as key stakeholders PSPS planning and execution. In alignment with D. 21-06-034, if Tribal entities were present within BVES's service area, they would be included in critical facility notifications and emergency coordination efforts.

- Schools
- Jails and prisons
- Senior and Independent Living Centers

6.4.3. Healthcare 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

6.4.4. Energy Sector: Public and private utility facilities vital to maintaining or restoring normal service, including, but not limited to, interconnected publicly-owned utilities.

6.4.5. Water and Wastewater Systems Sector: Facilities associated with the provision of drinking water or processing of wastewater including facilities used to pump, divert, transport, store, treat, and deliver water or wastewater.

6.4.6. Communications Sector: Communication carrier infrastructure including selective routers, central offices, head ends, cellular switches, remote terminals, and cellular sites.

6.4.7. Chemical Sector: Facilities associated with the provision of manufacturing, maintaining, or distributing hazardous materials and chemicals.

6.5. Key Partners. The following provides the list of pertinent Local Government, Agencies, and Partner Organizations to BVES PSPS notifications. This list overlaps with the list of what is considered critical facilities and infrastructure:

- Local officials (City of Big Bear Lake and San Bernardino County)
- State officials (normally CPUC Energy Division and Safety Enforcement Division)
- San Bernardino County Office of Emergency Services (County OES)
- Big Bear Fire Department
- California Department of Forestry and Fire Protection (CAL FIRE)
- U.S. Forest Service
- San Bernardino County Sheriff's Department Big Bear Lake Patrol Station
- California Highway Patrol (CHP) Arrowhead Area
- California Department of Transportation (Caltrans)
- Big Bear Area Regional Wastewater Agency (BBARWA)
- Big Bear City Community Services District (CSD)
- Big Bear Lake Water Department (DWP)
- Big Bear Municipal Water District (MWD)
- Southwest Gas Corporation
- Bear Valley Community Hospital
- Bear Valley Unified School District

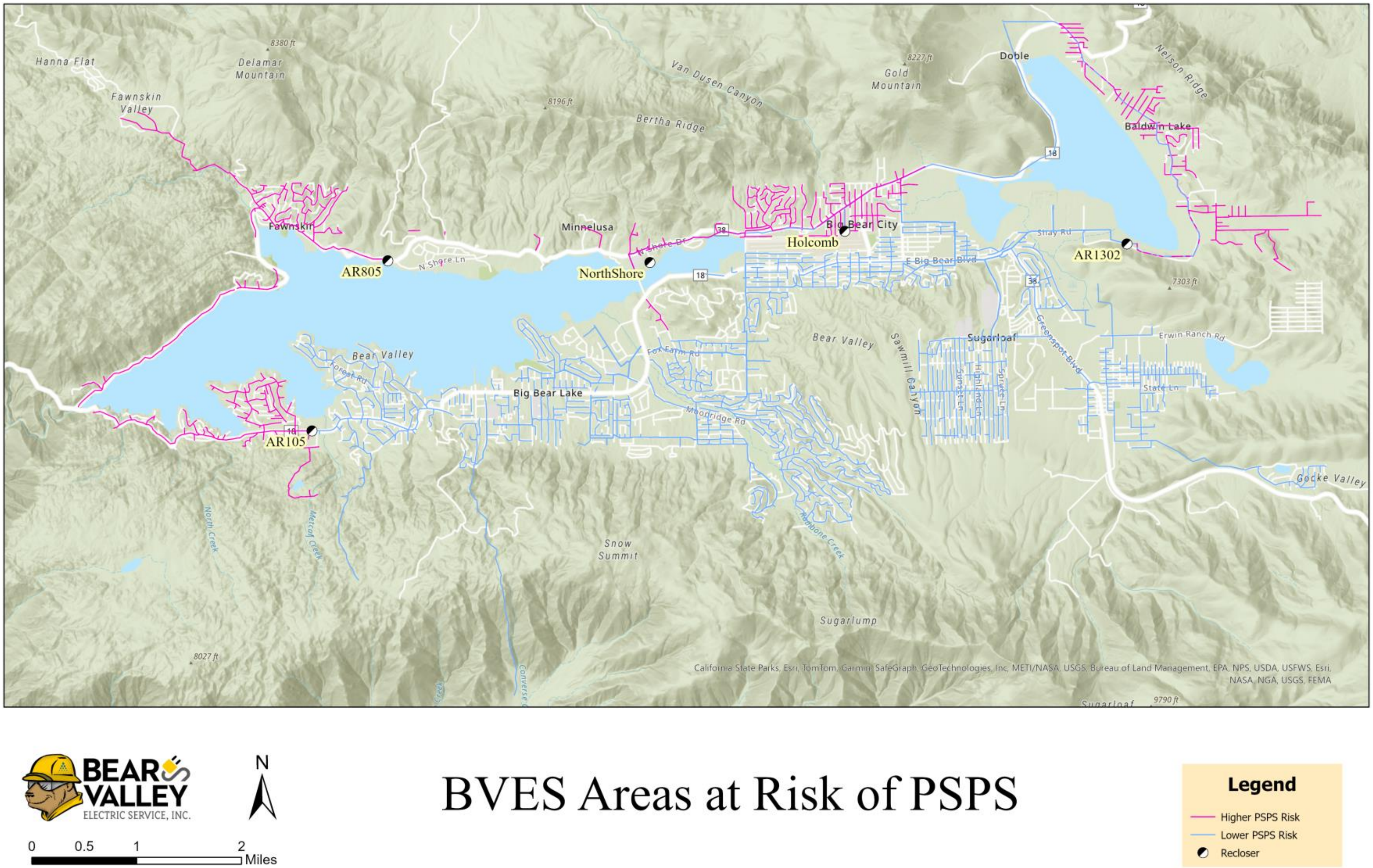
- Big Bear Chamber of Commerce
- Big Bear Airport District
- Big Bear Mountain Resorts
- Spectrum Communications
- Cell tower providers
- Community-Based Organizations (CBOs)
- AFN Community Representatives
- Independent Living Centers

7. **Compliance.** This document includes requirements invoked by:

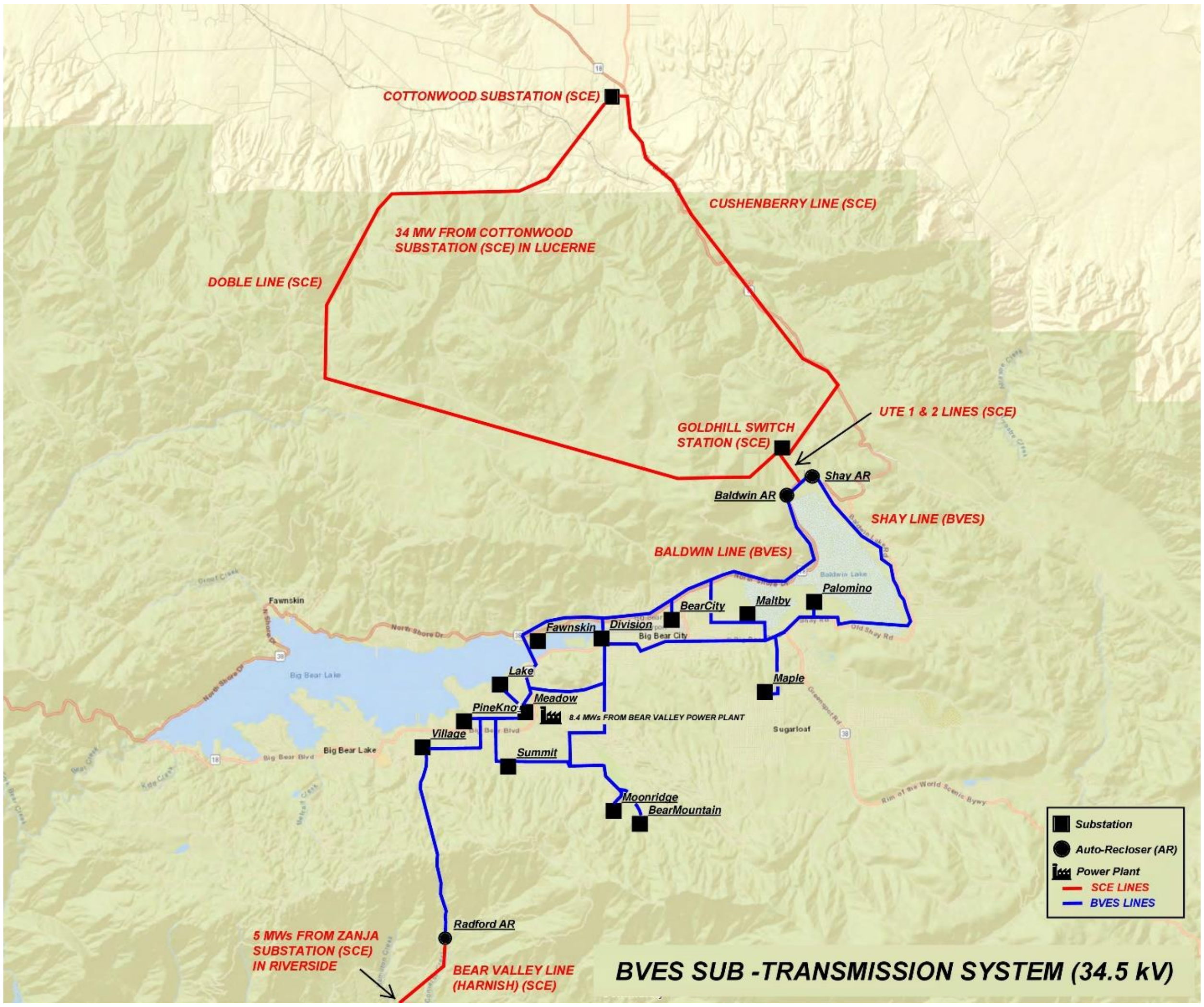
- Safety and Enforcement Division Resolution, Electric Safety and Reliability Branch Resolution ESRB-8 8 of July 12, 2018: Resolution Extending De-Energization Reasonableness, Notification, Mitigation and Reporting Requirements in Decision 12-04-024 to All Electric Investor-Owned Utilities (IOU).
- California Public Utilities Commission Decision 19-05-036 of May 30, 2019: Guidance Decision on 2019 Wildfire Mitigation Plans Submitted Pursuant to Senate Bill 901.
- California Public Utilities Commission Decision 19-05-040 of May 30, 2019: Decision on 2019 Wildfire Mitigation Plans of Liberty Utilities/CalPeco Electric; Bear Valley Electric Service, a Division of Golden State Water Company; and Pacific Power, a Division of PacifiCorp Pursuant to Senate Bill 901.
- California Public Utilities Commission Decision 19-05-042 of May 30, 2019: Decision Adopting De-Energization (Public Safety Power Shutoff) Guidelines (Phase 1 Guidelines).
- California Public Utilities Commission Decision 20-03-004 of March 12, 2020: Decision on Community Awareness and Public Outreach Before, During, and After a Wildfire, and Explaining Next Steps for Other Phase 2 Issues.
- California Public Utilities Commission Decision D20-05-051 of May 28, 2020: Decision Adopting Phase 2 Updated and Additional Guidelines for De-Energization of Electric Facilities to Mitigate Wildfire Risk.
- California Public Utilities Commission Enforcement Policy (2020): Outlines enforcement actions, penalty assessments, and compliance expectations related to PSPS and wildfire mitigation.
- California Public Utilities Commission Decision D21-06-024 of June 24, 2021: Decision Adopting Phase 3 Revised and Additional Guidelines and Rules for Public Safety Power Shutoffs (Proactive De-Energizations) of Electric Facilities to Mitigate Wildfire Risk caused by Utility Infrastructure.
- California Public Utilities Commission Wildfire Safety and Enforcement Branch (WSEB): Oversees regulatory enforcement for electrical infrastructure safety and PSPS compliance (2021).
- California Public Utilities Commission Unofficial Compendium of PSPS Guidelines (July 2022): Consolidates all PSPS-related guidelines into a single reference document for regulatory consistency.

- California Public Utilities Commission PSPS Citation Program (September 2023): Establishes a citation program for non-compliance with PSPS regulations, allowing penalties of up to $8 million per citation.

Appendix A: BVES "High Risk Areas" for PSPS Consideration



Appendix B: BVES Supply Lines, Sources of Power and Sub-Transmission System



APPENDIX C: COMMON ACRONYMS

Acronym	Definition
AAR	After Action Report
AR	Automatic Recloser
COA	Course of Action
DHS	U.S. Department of Homeland Security
EEG	Exercise Evaluation Guide
EOC	Emergency Operations Center
EPSS	Enhanced Power Line Safety Settings
FE	Functional Exercise
FEMA	Federal Emergency Management Agency
FPI	Fire Potential Index
HSEEP	Homeland Security Exercise and Evaluation Program
HSPD	Homeland Security Presidential Directive
HQ	Headquarters
ICS	Incident Command System
IP	Improvement Plan
ISR	Initial Situation Report
N/A	Not Available
NIMS	National Incident Management System
NRF	National Response Framework
NWS	National Weather Service
OPORD	Operations Order
Ops	Operations
PEDS	Protective Equipment and Device Settings
POC	Point of Contact
PPD	Presidential Policy Directive
RSOI	Reception, Staging, Onward Movement, and Integration
SitMan	Situation Manual
SME	Subject Matter Expert
SOG	Standard/Standing Operating Guidelines
TBD	To Be Determined
WFA-E	Wildfire Analyst Enterprise

Appendix H. **Asset and Inspection Quality Management Plan**

Bear Valley Electric Service, Inc. Asset & Inspection Quality Management Plan

December 28, 2021

Approved by: ____
Paul Marconi, President, Treasurer, & Secretary

1. **Purpose:** To provide policies and procedures to establish an audit process to manage and confirm work completed by employees or subcontractors complies with applicable technical specifications, standards, and codes and meet wildfire mitigation, safety, and reliability objectives.

2. **Scope:** The Quality Management Plan is applicable to all transmission and distribution (T&D) and power generation work with the exception of vegetation management work. A separate document, BVES INC Vegetation Management and Vegetation Management QC Programs Policy and Procedures, outlines the Quality Management Plan for vegetation management work.

3. **Definitions:**

3.1. Quality Assurance (QA) is the part of quality management focused on providing confidence that quality requirements will be fulfilled. The confidence provided by quality assurance is twofold —internally to management and externally to customers, government agencies, regulators, certifiers, and other stakeholders.

3.2. Quality Control (QC) is the part of quality management focused on fulfilling quality requirements. While quality assurance relates to how a process is performed or how a product is made, quality control is more the inspection aspect of quality management.

3.3. Quality Improvement is a set of activities that organizations carry out in order to enhance performance (get better results). Improvement can be achieved by means of a single activity or by means of a recurring set of activities.

3.4. Quality Management (QM) is the coordinated activities to direct and control and the organization with regard to quality.

3.5. Inspection is the process of measuring, examining, and testing to gauge one or more characteristics of a product or service and the comparison of these with specified requirements to determine conformity. Products, processes, and various other results can be inspected to make sure that the object coming off a production line, or the service being provided, is correct and meets specifications.

3.6. External (Contracted) T&D Work is defined as when scope of work where the majority and/or critical tasks are performed by a contractor.

3.7. Internal T&D Work is defined as when scope of work where the majority and/or critical tasks are performed by BVES employees.

3.8. Power Plant Work is defined as when the scope of work is on the Power Plant engines and/or supporting systems.

3.9. Substation Work is defined as when the scope of work is within the boundaries of a substation.

4. **Overview:** The primary goal of a Quality Management Plan is to ensure that the deliverables from work are of adequate quality and fit-for-purpose. Quality Assurance, Quality Control, and Quality Improvement are integral components of the Quality Management Plan. T&D and power generation work have a direct impact on wildfire mitigations, public and worker safety, and grid resiliency and reliability; therefore, it is essential that work is completed in a manner that is compliant with all applicable technical specifications, standards, and codes.

QA involves thinking about what is required to ensure quality will be achieved, and to set out processes, standards, procedures and/or policies to do that. Typical results of QA are quality plans, inspection and test plans (ITPs), documentation and training. It moves a step up from finding the failures to aiming to prevent or eliminate them. The focus of QA is to provide confidence that requirements and standards are met, and that processes and system have been followed. Some examples of QA:

- A checklist for assembly of product (the procedure/process as a series of steps that must be done).
- A written procedure.
- A set of processes for construction that cover the whole 'life cycle' from getting system requirements, through designing the system, procuring the materials or parts, constructing to applicable standards, testing, and placing in operation.
- A set of processes for a service that cover the whole 'life cycle' from establishing what the system requires, through designing the service, developing and delivering it.

QC is a procedure or set of procedures intended to ensure that a performed service adheres to a defined set of quality criteria or meets the applicable requirements and technical specifications. While QA refers to the confirmation that specified requirements have been met by a product or service, QC refers to the actual inspection of these elements. In order to implement an effective QC program, the organization must decide which specific standards and technical specifications must be met. Then the extent of QC actions must be determined -- for example, the percentage of structures to be inspected for each job and/or the level of detail for each inspection. Next, the results of the QC actions are analyzed to:

- Determine if quality requirements are being fulfilled,
- Expose areas where quality requirements are not being met,
- Identify areas for process improvement even if quality requirements are being fulfilled, and
- Evaluate if QC inspections are sufficient to determine if quality requirements are being fulfilled.

After this, corrective action and/or process improvements must be decided upon and taken, if warranted. Finally, the QC process must be ongoing to ensure that remedial efforts, if required, have produced satisfactory results and to immediately detect recurrences or new instances of trouble.

5. **Roles and Responsibilities:**

5.1. Utility Manager. Overall responsible for oversight of the quality management program. Table 6-1, BVES QA Process, in Section 6 details specific areas of responsibility.

5.2. Utility Engineer and Wildfire Mitigation Supervisor. Overall responsible for determining work scope, technical specifications, QA/QC requirements, evaluating QC results, and implementing QC requirements. Table 6-1, BVES QA Process, in Section 6 details specific areas of responsibility.

5.3. Field Operations Supervisor. Overall responsible for fieldwork and supporting the Utility Manager and Utility Engineer and Wildfire Mitigation Supervisor in their responsibilities. Table 6-1, BVES QA Process, in Section 6 details specific areas of responsibility.

5.4. Accounting Supervisor. Overall responsible for providing oversight of the procurement of equipment and material and the contracting of labor and services. Table 6-1, BVES QA Process, in Section 6 details specific areas of responsibility.

5.5. Regulatory Compliance Project Engineer. Responsible for supporting the Utility Engineer and Wildfire Mitigation Supervisor as detailed in Table 6-1, BVES QA Process, in Section 6.

5.6. Project Coordinator. Responsible for conducting QC activities as directed and supporting the Utility Engineer and Wildfire Mitigation Supervisor as detailed in Table 6-1, BVES QA Process, in Section 6.

5.7. GIS Specialist. Responsible for updating the GIS to document work completed and for supporting the Utility Engineer and Wildfire Mitigation Supervisor as detailed in Table 6-1, BVES QA Process, in Section 6.

5.8. Field Inspector. Responsible for conducting QC activities as directed and supporting the Utility Engineer and Wildfire Mitigation Supervisor as detailed in Table 6-1, BVES QA Process, in Section 6.

5.9. Substation Technician. Responsible for conducting QC activities as directed and supporting the Utility Engineer and Wildfire Mitigation Supervisor as detailed in Table 6-1, BVES QA Process, in Section 6.

5.10. Senior Power Plant Operator**.** Responsible for conducting QC activities as directed and supporting the Utility Engineer and Wildfire Mitigation Supervisor as detailed in Table 6-1, BVES QA Process, in Section 6.

5.11. Line Crew Foreman. Responsible for conducting QC activities as directed and supporting the Utility Engineer and Wildfire Mitigation Supervisor as detailed in Table 6-1, BVES QA Process, in Section 6.

5.12. Contracts Administrator. Responsible for ensuring qualified contractors are utilized for contracted work and that the contracting is in accordance with the Company's procurement policies as detailed in Table 6-1, BVES QA Process, in Section 6.

5.13. Buyer. Responsible for ensuring qualified vendors are utilized for procurement of equipment and materials, and that the purchasing is in accordance with the Company's procurement policies as detailed in Table 6-1, BVES QA Process, in Section 6.

5.14. Storekeeper. Responsible for receipt inspecting material and equipment to ensure it meets the specifications and quality requirements as required by the Purchase Order. Responsible for ensuring material and equipment is properly stored after receipt in accordance with manufacturer directions. Table 6-1, BVES QA Process, in Section 6 details specific areas of responsibility.

6. **Quality Management:** Table 6-1, BVES QA Process, outlines is the standard QA process that BVES follows to achieve the desired quality outcome for T&D and power generation work. Appendix A provides a flowchart of the QA process indicating steps that may be performed in parallel and process improvement loops. Depending on the complexity of the work, the Utility Engineer & Wildfire Mitigation Supervisor may require additional quality steps or may omit quality steps from the QA process as applicable to the specific work scope. Section 7 provides additional guidance on how the QA process is to be implemented.

Quality Step	Activity Description	Staff Involved
1	Determine scope of work (construction, repairs, inspections, etc.).	**Responsibility:** Utility Engineer & Wildfire Mitigation Supervisor. **Support:** Regulatory Compliance Project Engineer.
2	Establish applicable work technical specifications, instructions, standards, and material and equipment requirements (Work Order)	**Responsibility:** Utility Engineer & Wildfire Mitigation Supervisor. **Support:** Regulatory Compliance Project Engineer, Utility Planner, Engineering Technician, & Buyer.
3	Determine qualifications required of personnel performing the scope of work.	**Responsibility:** Utility Engineer & Wildfire Mitigation Supervisor. **Support:** Field Operations Supervisor.
4	Determine level of in process QC and work closeout and acceptance QC necessary to ensure quality requirements are satisfied.	**Responsibility:** Utility Engineer & Wildfire Mitigation Supervisor. **Support:** Field Operations Supervisor.

Quality Step	Activity Description	Staff Involved
5	Select staff to conduct applicable QC.	**Responsibility:** Utility Engineer & Wildfire Mitigation Supervisor. **Support:** Field Operations Supervisor.
6	Select qualified contractors (Request for Proposal) and/or staff to conduct the scope of work.	**Responsibility:** Utility Manager **Support:** Utility Engineer & Wildfire Mitigation Supervisor, Field Operations Supervisor, Regulatory Compliance Project Engineer, Accounting Supervisor, & Contracts Administrator.
7	Implement directed in process QC and work closeout QC.	**Responsibility:** Utility Engineer & Wildfire Mitigation Supervisor **Support (as applicable):** Regulatory Compliance Project Engineer, Engineering Technician, Project Coordinator, Field Inspector, Substation Technician, Senior Power Plant Operator, & Line Crew Foreman
8	Procure material and equipment (Purchase Order).	**Responsibility:** Buyer **Support (as applicable):** Accounting Supervisor
9	Receipt inspect material and equipment and properly store it.	**Responsibility:** Storekeeper **Support (as applicable):** Buyer, Accounting Supervisor
10	Commence work per scope of work.	**Responsibility:** Field Operations Supervisor **Support (as applicable):** Utility Manager, Utility Engineer & Wildfire Mitigation Supervisor, & Project Coordinator
11	Conduct directed in process QC at appropriate process control points.	**Responsibility:** Regulatory Compliance Project Engineer **Support (as applicable):** Engineering Technician, Project Coordinator, Field Inspector, Substation Technician, Senior Power Plant Operator, & Line Crew Foreman
12	Evaluate results of in process QC.	**Responsibility:** Regulatory Compliance Project Engineer **Support (as applicable):** Engineering Technician, Project Coordinator, Field Inspector, Substation Technician, Senior Power Plant Operator, & Line Crew Foreman
13	Determine if corrective action and/or process improvements warranted based on in process QC.	**Responsibility:** Utility Engineer & Wildfire Mitigation Supervisor **Support (as applicable):** Utility Manager, Field Operations Supervisor, & Project Coordinator.
14	Take corrective action if warranted based on in process QC.	**Responsibility:** Regulatory Compliance Project Engineer. **Support (as applicable):** Engineering Technician, Project Coordinator, Field Inspector, Substation Technician, Senior Power Plant Operator, & Line Crew Foreman.
15	Implement process improvements if warranted based on in process QC.	**Responsibility:** Utility Engineer & Wildfire Mitigation Supervisor. **Support (as applicable):** Utility Manager & Field Operations Supervisor.

Quality Step	Activity Description	Staff Involved
16	Determine if in process QC is appropriate. If not, implement additional or reduced in process QC as warranted.	**Responsibility:** Utility Engineer & Wildfire Mitigation Supervisor. **Support (as applicable):** Utility Manager & Field Operations Supervisor.
17	At work reported complete, document work performed (GIS update, work order closing, drawing update, inspection report, etc.).	**Responsibility:** Utility Engineer & Wildfire Mitigation Supervisor. **Support (as applicable):** Project Coordinator, GIS Specialist, Field Inspector, Substation Technician, Senior Power Plant Operator & Line Crew Foreman.
18	Conduct directed work closeout QC when work is completed.	**Responsibility:** Regulatory Compliance Project Engineer. **Support (as applicable):** Engineering Technician, Project Coordinator, Field Inspector, Substation Technician, Senior Power Plant Operator, & Line Crew Foreman.
19	Evaluate results of work closeout QC.	**Responsibility:** Regulatory Compliance Project Engineer **Support (as applicable):** Engineering Technician, Project Coordinator, Field Inspector, Substation Technician, Senior Power Plant Operator, & Line Crew Foreman
20	Determine if corrective action and/or process improvements warranted based on work closeout QC.	**Responsibility:** Utility Engineer & Wildfire Mitigation Supervisor **Support (as applicable):** Utility Manager, Field Operations Supervisor, & Project Coordinator.
21	Take corrective action if warranted based on work closeout QC.	**Responsibility:** Regulatory Compliance Project Engineer. **Support (as applicable):** Engineering Technician, Project Coordinator, Field Inspector, Substation Technician, Senior Power Plant Operator, & Line Crew Foreman.
22	If rework is necessary, ensure applicable in process QC and work close QC are conducted as appropriate.	**Responsibility:** Regulatory Compliance Project Engineer **Support (as applicable):** Engineering Technician, Project Coordinator, Field Inspector, Substation Technician, Senior Power Plant Operator, & Line Crew Foreman
23	Implement process improvements if warranted based on work closeout QC.	**Responsibility:** Utility Engineer & Wildfire Mitigation Supervisor. **Support (as applicable):** Utility Manager & Field Operations Supervisor.
24	Determine if work closeout QC is appropriate. If not, implement additional or reduced work closeout QC as warranted.	**Responsibility:** Utility Engineer & Wildfire Mitigation Supervisor. **Support (as applicable):** Utility Manager & Field Operations Supervisor.

Quality Step	Activity Description	Staff Involved
25	Closeout Work Order.	**Responsibility:** Utility Engineer & Wildfire Mitigation Supervisor. **Support (as applicable):** Field Operations Supervisor, Accounting Supervisor, Project Coordinator, GIS Specialist, Field Inspector, Substation Technician, Senior Power Plant Operator & Line Crew Foreman.

7. **Additional QM Guidance.** As discussed in Section 6, depending on the complexity of the work, the Utility Engineer & Wildfire Mitigation Supervisor (for T&D work) and Field Operations Supervisor (for Power Plant work) may require additional quality steps or may omit quality steps from the QA process as applicable to the specific work scope. This section provides guidance to be applied when making the determination for what QA will be applied to specific work and activities.

7.1. <u>Equipment and Material</u>.

7.1.1. *<u>Standard Stock Equipment and Material</u>:* The Utility Engineer & Wildfire Mitigation Supervisor shall approve the technical specifications of equipment and material to be maintained in standard inventory stock. Utility Engineer & Wildfire Mitigation Supervisor shall coordinate with the Field Operations Supervisor to determine standard stock minimum and maximum value amounts. Additionally, the Utility Engineer & Wildfire Mitigation Supervisor shall work with the Field Operations Supervisor when determining the specific technical specifications of material to be maintained in stock. The Buyer will place purchase orders for equipment and material to qualified vendors to replenish stock to avoid going below the minimum inventory amounts. The Storekeeper will receipt inspect all standard stock items and report discrepancies to the Buyer and Utility Engineer & Wildfire Mitigation Supervisor. For discrepancies affecting the technical specifications or performance of materials, the Utility Engineer & Wildfire Mitigation Supervisor will direct what corrective action(s) should be taken. For non-technical discrepancies (i.e., wrong amount of material received), the Buyer will direct what corrective action(s) should be taken.

7.1.2. *<u>Non-Standard Stock Equipment and Material</u>:* The Utility Engineer & Wildfire Mitigation Supervisor shall approve the technical specifications of non-standard stock equipment and material prior to purchasing. The Buyer will place purchase orders for the non-standard equipment and material as listed on the approved requisition to qualified vendors. When the equipment and material is received, the Storekeeper will receipt inspect it and will inform the Utility Engineer & Wildfire Mitigation Supervisor. The Utility Engineer & Wildfire Mitigation Supervisor will determine if an additional receipt inspection is necessary by a Subject Mater Expert. The following additional receipt inspections will be required by the Utility Engineer & Wildfire Mitigation Supervisor at a minimum:

- Substation equipment, capacitor banks, electronic fuse trip savers, and field switches will be receipt inspected by the Substation Technician.

- Distribution overhead and pad mounted transformers will be receipt inspected by a Journeyman Lineman or the Substation Technician.
- IT and communications equipment and material will be inspected by IT staff.
- Weather stations and other digital equipment and sensors will be receipt inspected by IT staff, Substation Technician and/or other SME staff as designated by the Utility Engineer & Wildfire Mitigation Supervisor.
- Meters and meter related equipment and material shall be receipt inspected by the Meter Testman.
- Power Plant equipment and material will be receipt inspected by the Power Plant Senior Operator.

Discrepancies noted in the receipt inspections shall be reported to the Buyer and Utility Engineer & Wildfire Mitigation Supervisor. For discrepancies affecting the technical specifications or performance of materials, the Utility Engineer & Wildfire Mitigation Supervisor will direct what corrective action(s) should be taken. For non-technical discrepancies (i.e., wrong amount of material received), the Buyer will direct what corrective action(s) should be taken.

7.1.3. *Equipment and Material Ordered for Specific Projects:* The Utility Engineer & Wildfire Mitigation Supervisor will direct if any additional SME receipt inspection(s) are necessary in addition to the Storekeeper's receipt inspection for equipment and material ordered to support a specific project. For example, if the equipment and material is the same equipment and material maintained in stock, the Storekeeper's receipt inspection would normally be sufficient. The Utility Engineer & Wildfire Mitigation Supervisor should use the guidance in Section 7.1.2 to determine if additional receipt inspections are necessary.

7.2. Contracted Services. The Utility Manager shall be responsible for contracting for work from qualified contractors by following the Company's procurement policy. In coordination with the Utility Engineer & Wildfire Mitigation Supervisor, Field Operations Supervisor, Accounting Supervisor, and Contracts Administrator, the Utility Manager shall develop the contracted scope of work and issue a Request for Proposal to qualified contractors. The Utility Manager shall follow the Company's procurement policy in selecting the best value bid from qualified contractors and awarding the contract.

7.3. External (Contracted) T&D Work. In coordination with the Field Operations Supervisor, the Utility Engineer & Wildfire Mitigation Supervisor shall approve specific in-process and closeout QC checks for external T&D work. The Utility Engineer & Wildfire Mitigation Supervisor shall utilize the following guidance:

- Prior to authorizing work, the Utility Engineer & Wildfire Mitigation Supervisor shall review and approve the design, construction drawings, and technical specifications and then issue a Work Order to direct the specified work.

- The Utility Manager shall establish a contract with a qualified contractor per the Company's procurement policy.
- Equipment and material shall be ordered per Section 7.1 above as applicable once the Work Order is opened.
- The Utility Engineer & Wildfire Mitigation Supervisor in coordination with the Field Operations Supervisor shall determine the specific in process and closeout QC checks to be conducted and select the staff that will conduct the QC checks. Generally, QC checks shall be performed by the Field Inspector or a BVES Journeyman Lineman Foreman.
- Staff that will be involved in the QC checks shall review the Work Order.
- Once the Work Order is authorized, equipment and material is received, contract in place for the contracted work, and the work schedule supports the work, the Field Operations Supervisor in coordination with the Project Coordinator will direct the contractor to conduct the work.
- In-process QC checks may be designated to be conducted periodically (for example, daily when work is in progress), randomly (for example, unannounced when work is in progress), as task related inspections (for example, prior to installing a ground rod the BVES inspector must be on site), and/or a combination the later methods.
- Results of in-process QC checks should be reviewed with the Regulatory Compliance Project Engineer and the Utility Engineer & Wildfire Mitigation Supervisor and corrective action directed if necessary.
- Closeout QC checks shall be designed to confirm the as-built drawings, inspect the quality of the workmanship, and ensure that the designated materials were installed. Additionally, the closeout QC checks will include an audit of the Work Order package.
- When work is reported complete, the Field Operations Supervisor shall direct closeout QC checks be conducted.
- Results of closeout QC checks should be reviewed with the Regulatory Compliance Project Engineer and the Utility Engineer & Wildfire Mitigation Supervisor and corrective action directed if necessary.
- Upon receipt of an invoice for the work, the Project Coordinator shall perform a work package audit and validate the materials and work performed. Project Coordinator shall also perform a validation of billing units, and ensures the Field Inspector's verification of work completion and approval for billing. Invoices will not be approved unless the work meets required standards per the scope of work.

The Utility Engineer & Wildfire Mitigation Supervisor shall review the results of in process and closeout QC checks and the completed Work Order package and will direct re-work and/or other corrective action if necessary. Once, the Utility Engineer & Wildfire Mitigation Supervisor is satisfied the work is of satisfactory quality, the Work Order may be closed out.

7.4. <u>Internal T&D Work</u>. In coordination with the Field Operations Supervisor, the Utility Engineer & Wildfire Mitigation Supervisor shall approve specific in process and closeout QC checks internal T&D work. The Utility Engineer & Wildfire Mitigation Supervisor shall utilize the following guidance:

- Prior to authorizing work, the Utility Engineer & Wildfire Mitigation Supervisor shall review and approve the design, construction drawings, and technical specifications and then issue a Work Order to direct the specified work.
- Equipment and material shall be ordered per Section 7.1 above as applicable once the Work Order is opened.
- The Utility Engineer & Wildfire Mitigation Supervisor in coordination with the Field Operations Supervisor shall determine the specific in process and closeout QC checks to be conducted and select the staff that will conduct the QC checks. Generally, QC checks shall be performed by a BVES Journeyman Lineman Foreman.
- Staff that will be involved in the QC checks shall review the Work Order.
- Once the Work Order is authorized, equipment and material is received, contract in place for the contracted work, and the work schedule supports the work, the Field Operations Supervisor in coordination with the Project Coordinator will direct the BVES crew to conduct the work.
- In-process QC checks may be designated to be conducted periodically (for example, daily when work is in progress), randomly (for example, unannounced when work is in progress), as task related inspections (for example, prior to installing a ground rod the BVES inspector must be on site), and/or a combination the later methods.
- Results of in-process QC checks should be reviewed with the Regulatory Compliance Project Engineer and the Utility Engineer & Wildfire Mitigation Supervisor and corrective action directed if necessary.
- Closeout QC checks shall be designed to confirm the as-built drawings, inspect the quality of the workmanship, and ensure that the designated materials were installed. Additionally, the closeout QC checks will include an audit of the Work Order package.
- When work is reported complete, the Field Operations Supervisor shall direct closeout QC checks be conducted.
- Results of closeout QC checks should be reviewed with the Regulatory Compliance Project Engineer and the Utility Engineer & Wildfire Mitigation Supervisor and corrective action directed if necessary.
- The Regulatory Compliance Project Engineer shall perform a work package audit and validate the materials and work performed.

The Utility Engineer & Wildfire Mitigation Supervisor shall review the results of in process and closeout QC checks and the completed Work Order package and will direct re-work and/or other corrective action if necessary. Once, the Utility Engineer & Wildfire Mitigation Supervisor is satisfied the work is of satisfactory quality, the Work Order may be closed out.

7.5. Substation Work. The Utility Engineer & Wildfire Mitigation Supervisor shall approve specific in process and closeout QC checks for substation work. The Utility Engineer & Wildfire Mitigation Supervisor shall utilize the following guidance:

- Prior to authorizing work, the Utility Engineer & Wildfire Mitigation Supervisor shall review and approve the design, construction drawings, and technical specifications and then issue a Work Order to direct the specified work.
- The Utility Engineer & Wildfire Mitigation Supervisor shall approve a specific testing and commissioning program that must be satisfactorily completed prior to accepting major substation work.
- The Utility Manager shall establish a contract with a qualified contractor per the Company's procurement policy.
- Equipment and material shall be ordered per Section 7.1 above as applicable once the Work Order is opened.
- The Utility Engineer & Wildfire Mitigation Supervisor in coordination with the Field Operations Supervisor shall determine the specific in process and closeout QC checks to be conducted and select the staff that will conduct the QC checks. Generally, QC checks shall be performed by the Substation Technician or a BVES Journeyman Lineman Foreman.
- Staff that will be involved in the QC checks shall review the Work Order.
- Once the Work Order is authorized, equipment and material is received, contract in place for the contracted work, and the work schedule supports the work, the Field Operations Supervisor in coordination with the Project Coordinator will direct the contractor to conduct the work.
- In-process QC checks may be designated to be conducted periodically (for example, daily when work is in progress), randomly (for example, unannounced when work is in progress), as task related inspections (for example, prior to making up switch connections, the BVES inspector must be on site), and/or a combination the later methods.
- Results of in-process QC checks should be reviewed with the Regulatory Compliance Project Engineer and the Utility Engineer & Wildfire Mitigation Supervisor and corrective action directed if necessary.
- Closeout QC checks shall be designed to confirm the as-built drawings, inspect the quality of the workmanship, and ensure that the designated materials were installed. Additionally, the closeout QC checks will include an audit of the Work Order package.
- When work is reported complete, the Field Operations Supervisor shall direct closeout QC checks be conducted.
- Results of closeout QC checks should be reviewed with the Regulatory Compliance Project Engineer and the Utility Engineer & Wildfire Mitigation Supervisor and corrective action directed if necessary.
- When conditions are met, the Field Operations Supervisor shall direct performance of the testing and commissioning program. The testing and commissioning program should generally be conducted by a third party independent of the contractor performing the work and/or the Substation Technician. The Substation Technician shall oversee any third party that performs the testing and commissioning program.
- The Utility Engineer & Wildfire Mitigation Supervisor shall review the results of the testing and commissioning program prior to accepting the work as being complete.

- Upon receipt of an invoice for the work, the Project Coordinator shall perform a work package audit and validate the materials and work performed. Project Coordinator also performs a validation of billing units, and ensures the Substation Technician's verification of work completion and approval for billing. Invoices will not be approved unless the work meets required standards per the scope of work.

Utility Engineer & Wildfire Mitigation Supervisor shall review the results of closeout QC checks and testing and commissioning program, and will direct re-work and/or other corrective action if necessary. Once, the Utility Engineer & Wildfire Mitigation Supervisor is satisfied the work is of satisfactory quality, the Work Order may be closed out.

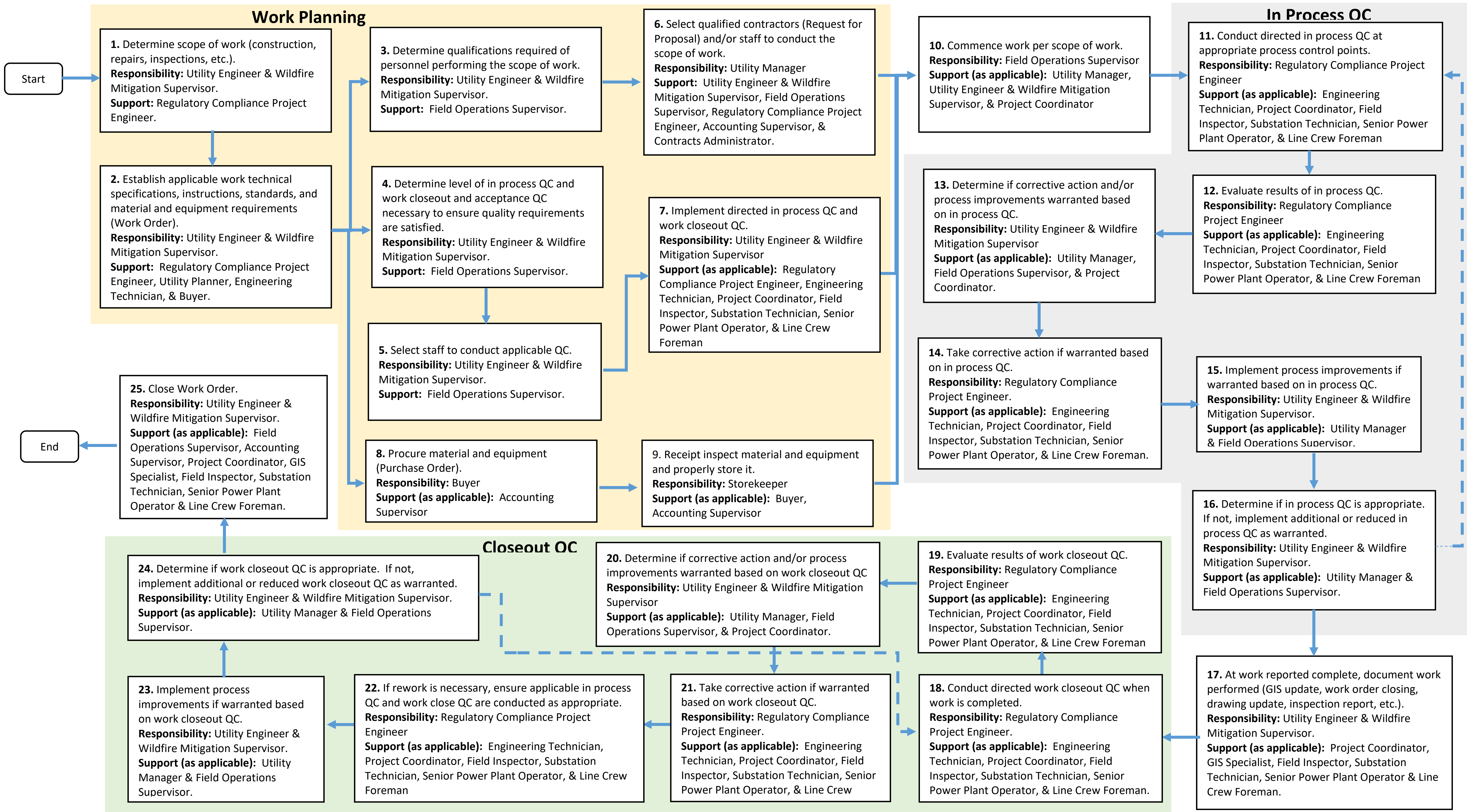
7.6. Power Plant Work. The Field Operations Supervisor in coordination with the Senior Power Plant Operator shall approve specific in process and closeout QC checks for power plant work. The Field Operations Supervisor shall utilize the following guidance:

- Prior to authorizing work, the Field Operations Supervisor in coordination with the Senior Power Plant Operator shall review and approve the design, construction drawings, and technical specifications and then issue a Work Order with Engineering and Planning support to direct the specified work.
- The Field Operations Supervisor in coordination with the Senior Power Plant Operator shall approve a specific testing and commissioning program that must be satisfactorily completed prior to accepting major power plant work.
- The Utility Manager shall establish a contract with a qualified contractor per the Company's procurement policy.
- Equipment and material shall be ordered per Section 7.1 above as applicable once the Work Order is opened.
- The Field Operations Supervisor in coordination with the Senior Power Plant Operator shall determine the specific in process and closeout QC checks to be conducted and select the staff that will conduct the QC checks. Generally, QC checks shall be performed by the Senior Power Plant Operator or Power Plant Operator.
- Staff that will be involved in the QC checks shall review the Work Order.
- Once the Work Order is authorized, equipment and material is received, contract in place for the contracted work, and the work schedule supports the work, the Field Operations Supervisor in coordination with the Project Coordinator will direct the contractor to conduct the work.
- In-process QC checks may be designated to be conducted periodically (for example, daily when work is in progress), randomly (for example, unannounced when work is in progress), as task related inspections (for example, prior to reassembly of an engine cylinder, the BVES inspector must be on site), and/or a combination the later methods.
- Results of in-process QC checks should be reviewed with the Field Operations Supervisor and the Senior Power Plant Operator and corrective action directed if necessary.

- Closeout QC checks shall be designed to confirm the as-built drawings, inspect the quality of the workmanship, and ensure that the designated materials were installed. Additionally, the closeout QC checks will include an audit of the Work Order package.
- When work is reported complete, the Field Operations Supervisor shall direct closeout QC checks be conducted.
- Results of closeout QC checks should be reviewed with the Field Operations Supervisor and the Senior Power Plant Operator and corrective action directed if necessary.
- When conditions are met, the Field Operations Supervisor shall direct performance of the testing and commissioning program. The testing and commissioning program should generally be conducted by a third party independent of the contractor performing the work and/or the Senior Power Plant Operator. The Senior Power Plant Operator shall oversee any third party that performs the testing and commissioning program.
- The Field Operations Supervisor and the Senior Power Plant Operator shall review the results of the testing and commissioning program prior to accepting the work as being complete.
- Upon receipt of an invoice for the work, the Project Coordinator shall perform a work package audit and validate the materials and work performed. Project Coordinator also performs a validation of billing units, and ensures the Senior Power Plant Operator's verification of work completion and approval for billing. Invoices will not be approved unless the work meets required standards per the scope of work.

The Field Operations Supervisor and Senior Power Plant Operator shall review the results of closeout QC checks and testing and commissioning program, and will direct re-work and/or other corrective action if necessary. Once, the Utility Engineer & Wildfire Mitigation Supervisor is satisfied the work is of satisfactory quality, the Work Order may be closed out.

Appendix A: BVES QA Process Flow Chart



Appendix I. **BVES Vegetation Management and Vegetation Management QC Programs Policy Procedures**

Bear Valley Electric Service, Inc.
Vegetation Management
and
Vegetation QA/QC Programs

October 6, 2021

Approved by: ____
Paul Marconi, President, Treasurer, & Secretary

1. Purpose: Provide requirements for the Vegetation Management (VM) program and VM quality assurance (QA)/quality control (QC) program at Bear Valley Electric Service, Inc. (BVES).

2. Background: Proper clearance of vegetation around high voltage power lines is essential to public safety and ensuring the transmission and distribution (T&D) system is reliable. BVES has established vegetation clearance standards to achieve safe and reliable T&D operations, which are described in Section 3. Efficient, effective, and sustained implementation of the standards is the objective of the VM program described in Section 4. Violation of BVES's vegetation clearance standards significantly increases the risk of ignitions and; therefore, utility caused wildfires when combined with dry weather conditions and high winds. Additionally, such violations increase the probability of vegetation caused outages.

BVES utilizes contractors to provide vegetation clearance services to maintain clearance standards. Ensuring that vegetation clearance operations are actually being performed to the desired standards is an essential element of mitigating the risk of ignition and outages. Therefore, BVES established a VM QA/QC program. The VM QA program is focused on providing confidence that quality requirements will be fulfilled. The VM QC program requires that certain designated BVES Staff perform VM QC checks on a frequent basis. The results of the VM QA/QC programs are essential to alerting BVES to the state of its VM program, which is a critical element for public safety. Section 5 provides guidance on the VM QA/QC program. Having assurance that vegetation clearance efforts are meeting our standards is essential to ensuring public safety from utility caused wildfires. It is critical that if there are problems in vegetation clearance, that BVES is aware of the problems and is able to then dedicate the proper resources toward vegetation clearance efforts to make it effective and resolve any problem areas.

Effective vegetation management requires specialized subject matter expertise; therefore, BVES at times may engage forester consulting services. Some of the duties that may be assigned to the forester include: inspections, auditing, customer contacts and issue resolution, work plans development, specialized projects, contractor safety observations, and vegetation management program documentation and data analysis.

3. Vegetation Clearance Standards: California Public Utilities Commission (CPUC) General Order 95 (GO-95), Rules for Overhead Electric Line Construction, Rule 35 Vegetation Management and Appendix E Guidelines to Rule 35 (trimming guidelines) provides minimum vegetation clearance standards applicable to BVES's T&D system.

3.1. For reference, BVES' Service Area is entirely within a "High Fire-Threat District" with areas classified as Zone 1 and Tiers 2 and 3 per Rule 21.1 of GO-95. Based upon GO-95 requirements (48 inches minimum radial clearance) and on the local climate, likelihood of icing conditions, tree limbs and branches subject to weakening due to high winds and snow weight, elevation, local conditions and access to vegetation for trimming, and species growth rates and characteristics, **the minimum allowable radial clearance of bare line conductors from vegetation is 72 inches** in the BVES service area.

3.2. BVES has established the following requirements to safe clearance along bare line conductors is maintained throughout the BVES service area during the entire length of the vegetation management program cycle:

- **Radial Clearances:** Vegetation that is within the minimum 72-inch safe clearance distance will be trimmed to at least 12 feet in accordance with Appendix E Guidelines to Rule 35 of GO-95. Taking into account vegetation species and growth rates and characteristics, BVES's contractor will trim beyond 12 feet if necessary to ensure that the vegetation remains outside the minimum 72-inch safe clearance distance for the entire length of the vegetation management program cycle (3-years).

    - Vegetation that is outside the minimum 72-inch safe clearance distance but is expected, taking into account vegetation species and growth rates and characteristics, to encroach the 72-inch safe clearance distance prior to the next scheduled preventative vegetation management visit (normally 3 years) will be trimmed to at least 12 feet in accordance with Appendix E Guidelines to Rule 35 of GO-95. Taking into account vegetation species and growth rates and characteristics, BVES's contractor will trim beyond 12 feet if necessary to ensure that the vegetation remains outside the minimum 72-inch safe clearance distance for the entire length of the vegetation management program cycle (3-years).
    - Anytime it is determined that trimming of vegetation is necessary, BVES's contractor shall trim to least 12 feet in accordance with Appendix E Guidelines to Rule 35 of GO-95. Taking into account vegetation species and growth rates and characteristics, BVES's contractor will trim beyond 12 feet if necessary to ensure that the vegetation remains outside the minimum 72-inch safe clearance distance for the entire length of the vegetation management program cycle (3-years).
    - In so far as possible, trimming shall be designed to achieve the appropriate clearance from the power lines without damaging the structural integrity or health of the tree(s).

- **Blue Sky Requirement:** No vertical coverage shall be allowed above BVES sub-transmission lines (34.5 kV).
- **Fast Growing Trees:** All fast growing trees, (poplar, aspen, cottonwood…) will be trimmed to at least 12 feet and removal will be considered. BVES's contractor may determine that additional clearance would be prudent based on growth factors, wind, ice, etc.
- **Drip Line:** All vegetation within the drip line of primary conductors that has the potential of growing into the secondary system or within 12 feet of the energized primary conductors within the 3-year vegetation management program cycle will be removed.
- **Tree Trunk and Major Limb Exception:** Per Section 3.3 below and Appendix A, Trees and Major Limbs in Close Proximity to Bare Conductors, flow chart.
- **Tree Removal:** Trees that are dead, rotten or diseased or dead, rotten or diseased portions of otherwise healthy trees which overhang or lean toward and may fall into a span of power

lines, said trees or portions thereof should be removed. Note that this may apply to trees outside the clearance zone (for example, a dead tree across the street may pose a danger to BVES power lines).

- **Base of Poles/Structures:** For poles or structures that have non-exempt equipment per CALFIRE requirements, all flammable material and vegetation in a 10-foot radius around the base of the pole or structure shall be cut down and removed during each normal vegetation management cycle clearance visit. Exceptions per the effective California Power Line Fire Prevention Field Guide are authorized.
- **Right of Way:** All brush, limbs and foliage in the right of way (ROW) shall be cut up to 8-feet above the ground. All dead, dying, diseased or dried vegetation from 8 feet above the ground to the top of the power lines must be cut down during each normal vegetation management cycle clearance visit. This requirement is applicable to all ROWs in the HFTD Tier 3 and to all ROWs in the HFTD Tier 2 designated as having high strike potential by the Wildfire Mitigation & Safety Engineer. Exceptions per the effective California Power Line Fire Prevention Field Guide are authorized.

3.3. Tree Trunk and Major Limb Exception. Appendix A, Trees and Major Limbs in Close Proximity to Bare Conductors, provides the information in this section in flowchart format. If a mature tree whose trunk or major limb is within 48 inches of bare conductors, take the following action:

3.3.1. If the tree or major limb is within 12 inches of the bare conductors regardless of thickness at conductor level, this is a Level 1 discrepancy and shall be immediately remediated by:

- Removing the tree or limb immediately, or
- Installing a tree guard on the line to prevent the tree or limb from contacting the bare conductors and designating the discrepancy as a Level 2 discrepancy to be corrected by removing the tree within 6 months.

3.3.2. If the tree or major limb is less than 6 inches thick at conductor level, then the tree or major limb must be trimmed or removed to achieve 72 inches clearance from bare conductors as follows:

3.3.2.1. If there are no burn marks or evidence of the tree or limb making contact with bare conductors and the clearance is greater than 48 inches, then this is a Level 2 discrepancy and shall be corrected within 12 months.

3.3.2.2. If there are no burn marks or evidence of the tree or limb making contact with bare conductors and the clearance is less than 48 inches but greater than 18 inches, then this is a Level 2 discrepancy and shall be corrected within 180 days. A tree guard should be installed as soon as operationally possible.

3.3.2.3. If there are burn marks or evidence of the tree or limb making contact with bare conductors and/or the clearance is less than 18 inches, then this is a Level 1 discrepancy and shall be immediately remediated by:

- Removing the tree or limb immediately, or
- Installing a tree guard on the line to prevent the tree or limb from contacting the bare conductors and designating the discrepancy as a Level 2 discrepancy to be corrected by removing the tree within 6 months.

3.3.3. If the tree or major limb is greater than 6 inches thick at conductor level and greater than 12 inches from bare conductors, then the tree or major limb shall be evaluated to determine if an exemption per GO-95 Rule 35 may be applied. Take the following action:

3.3.3.1. If there are burn marks present on the tree or major limb or evidence of the tree or limb making contact with the bare conductor, this is a Level 1 discrepancy and shall be immediately remediated by:

- Removing the tree or major limb immediately, or
- Installing a tree guard on the line to prevent the tree or limb from contacting the bare conductors and designating the discrepancy as a Level 2 discrepancy to be corrected by removing the tree within 6 months.

3.3.3.2. If there are no burn marks present on the tree or major limb and no evidence of the tree or limb making contact with the bare conductor, then the tree or major limb may be exempted provided the following:

- Tree has been established in its current location for at least 10 years.
- Tree trunk has a diameter at breast height (DBH) of at least 10”.
- Tree or limb at the conductor level is at least 6” in diameter.
- Tree is not re-sprouting at conductor level during the time of inspection.
- Tree is healthy and not otherwise hazardous.
- Tree is not easily climbable. Note the tree clearance crew can remove branches to render a tree not easily climbable.

3.3.3.3. If the tree cannot satisfy one or more of the above criteria (Section 3.3.3.2), then the tree or major limb must be removed. It should be designated as a Level 2 discrepancy and shall be corrected within 12 months.
3.3.3.4. If the tree satisfies all of the above criteria (Section 3.3.3.2), then the tree may be exempted and remain in place. The tree shall be:

- Documented on Major Woody Stem Form and approved by the Wildfire Mitigation & Reliability Engineer.
- Tracked in the Company’s GIS applications for vegetation management.

- Re-evaluated each year.
- As a precaution, install a tree guard when operationally feasible.

4. Vegetation Management Program: The VM program is designed to ensure the standards described in Section 3 are achieved and sustained throughout the BVES service area.

4.1. Wildfire Mitigation & Reliability Engineer. The VM program shall be the responsibility of the Wildfire Mitigation & Reliability Engineer. Specifically, the Wildfire Mitigation & Reliability Engineer shall:

4.1.1. Establish and ensure BVES's vegetation clearance standards (Section 3) comply with state law, CPUC regulations and other higher authority requirements and achieve the desired public safety and reliability goals of the program given the local environmental conditions of the BVES service area.
4.1.2. Recommend to the President any changes to the BVES vegetation clearance standards (Section 3) that may be required due to:

- Changes in the law, CPUC regulations, other higher authority requirements, and
- Changes in the local service area environment (for example, extended draught conditions, tree pest infestations, etc.) that may warrant a change in clearance standards.

4.1.3. Ensure BVES applies sufficient resources to maintain the BVES vegetation clearance standards (Section 3) throughout the service area.
4.1.4. Recommend to the Utility Manager changes to vegetation management resources as appropriate to maintain compliance with the BVES vegetation clearance standards (Section 3).
4.1.5. Manage all aspects of vegetation management contracts in accordance with BVES's procurement policy. This shall include drafting requests for proposals (RFPs) as applicable, assisting in selecting contractors via the BVES bidding process, reviewing and approving invoices for the Utility Manager or President approval as applicable.
4.1.6. Perform the duties of the BVES Authorized Representative for vegetation management contracts and ensure the contractor is performing in accordance with the contract requirements.
4.1.7. Ensure contractor employees conducting vegetation clearance work are properly trained and certified as required by state law.
4.1.8. Coordinate with contractors and Field Operations to cover power lines or de-energize lines as needed.
4.1.9. Inform Field Operations Supervisor and Customer Program Specialist where vegetation clearance operations will be conducted each week.
4.1.10. Work with the Customer Program Specialist to generate or update customer outreach to educate customers on vegetation management efforts in the BVES service area.
4.1.11. Work with the Customer Service Supervisor or applicable Customer Service staff to resolve customer inquiries or disputes involving vegetation clearance efforts.

4.1.12. Coordinate with the City of Big Bear Lake, County of San Bernardino, U.S. Forest Service, CALFIRE, Big Bear Fire Department, and other applicable stakeholders in the area of vegetation clearance efforts.
4.1.13. Coordinate with the City of Big Bear Lake, County of San Bernardino, U.S. Forest Service, CALFIRE, Big Bear Fire Department, and other applicable stakeholders in the area of fuels management efforts by the community.
4.1.14. Manage all aspects of the VM QA/QC program as described in Section 5.
4.1.15. Work closely with the GIS Specialist and contractors to ensure the vegetation clearance efforts are properly documented in the GIS and associated applications.
4.1.16. Work closely with the GIS Specialist to develop overlays to support presentations and documents regarding the vegetation management program.
4.1.17. Manage and provide oversight of the Third Party Patrols, LiDAR Surveys, Fly-over UAV Surveys, etc., while working closely with the Field Inspector to ensure line inspection programs such as GO-165 Detailed Inspections and GO-165 Patrols are being conducted in compliance with CPUC regulations and BVES requirements and vegetation clearance discrepancies are being identified by the inspections.
4.1.18. Manage and provide oversight of the Forester's work activities when assigned. Some of the duties that may be assigned to the Forester include: inspections, auditing, customer contacts and issue resolution, work plans development, specialized projects, contractor safety observations, and vegetation management program documentation and data analysis.
4.1.19. Issues or causes to be issued vegetation orders to the contractor.
4.1.20. Review the results of line inspection programs such as GO-165 Detailed Inspections, GO-165 Patrols, Third Party Patrols, LiDAR Surveys, Fly-over UAV Surveys, etc. and ensuring any vegetation discrepancies are tracked and resolved. This is normally done by issuing or causing to be issued vegetation orders to the contractor.
4.1.21. Discrepancies of a significant safety nature that would be classified as Level 1 per GO-95 Rule 18 should be resolved immediately by notifying the Field Operations Supervisor or Field Inspector who will send the appropriate crew to resolve the issue in an expedient manner. If unable to reach the Field Operations Supervisor or Field Inspector, then notify the Service Crew or Dutyman to resolve the issue.

Examples of Level 1 vegetation discrepancies are vegetation contacting, nearly contacting or arcing to high voltage conductor, vegetation contacting low voltage conductor and compromising structure, etc.

4.1.21.1. Other vegetation discrepancies of an urgent nature (Level 2) but do not rise to the Level 1 classification should be assigned to the contractor as a vegetation order with requirement to resolve within 30-days. Examples of Level 2 vegetation discrepancies are vegetation within 48 inches of high voltage lines, vegetation causing strain or abrasion on low voltage conductor, tree or portions of tree that are dead, rotten or diseased that may fall into power lines, etc.
4.1.21.2. Non-urgent vegetation discrepancies should be tracked as Level 3 discrepancies and resolved by the contractor during the normal vegetation cycle.

4.1.22. Support the preparation of regulatory reports, General Rate Case testimony, Wildfire Mitigation Plan updates, Data Requests and other regulatory requests regarding vegetation management issues.
4.1.23. Support CPUC audits, Office Infrastructure Safety (OEIS) site visits, and other authorized agency reviews of vegetation management.

4.2. Utility Manager. Provides oversight of the VM and VM QA/QC programs. Specifically:

4.2.1. Reviews reports and directs changes to the program as deemed necessary. Keeps the President informed of such changes.
4.2.2. Ensures the VM program is properly resourced. Prepares annual O&M budget for vegetation management efforts.
4.2.3. Responsible for ensuring vegetation contracts are in place and managed per the BVES procurement policy.
4.2.4. Responsible for preparing regulatory reports, General Rate Case testimony, Wildfire Mitigation Plan updates, Data Requests responses and other regulatory requests regarding vegetation management issues. These should all be forwarded to the Regulatory Affairs Manager and the President prior to issuing.
4.2.5. Provides oversight of the VM QA/QC programs described in Section 5.
4.2.6. Responsible for supporting CPUC audits, OEIS site visits, and other authorized agency reviews of vegetation management.

4.3. Utility Engineer & Wildfire Mitigation Supervisor. Provides oversight of the Wildfire Mitigation & Reliability Engineer in managing the VM and VM QA/QC programs. Specifically:

4.3.1. Responsible for ensuring VM QA annual audit and quarterly vegetation management assessments are timely, complete, and accurate in accordance with Section 5.
4.3.2. Responsible for ensuring the Wildfire Mitigation & Reliability Engineer has adequate tools and staff support (GIS, Administrative, etc.) to properly manage the VM and VM QA/QC programs.
4.3.3. Responsible for reviewing vegetation requirements and ensuring the VM program is in compliance with requirements.
4.3.4. Responsible for ensuring VM program is executed per this procedure and BVES's current Wildfire Mitigation Plan.
4.3.5. Responsible for CPUC audits, OEIS site visits, and other authorized agency reviews of vegetation management. Coordinates closely with the Field Operations Supervisor on these matters and all communications with regulatory agencies through the Utility Manager and President.

4.4. Field Operations Supervisor. Provides support to the Wildfire Mitigation & Reliability Engineer in managing the VM and VM QA/QC programs. Specifically:

4.4.1. Provides support as needed to de-energize or cover lines as applicable and provides assistance in resolving vegetation discrepancies.

4.4.2. Closely supports the Utility Engineer & Wildfire Mitigation Supervisor on CPUC audits, OIES site visits, and other authorized agency reviews of vegetation management.
4.4.3. Ensures Field Inspector works closely with the Wildfire Mitigation & Reliability Engineer to achieve VM program requirements.

4.5. <u>Field Inspector</u>**.** Supports the Wildfire Mitigation & Reliability Engineer in the area of line inspections with regard to identifying, documenting, and tracking vegetation clearance discrepancies. Specifically:

4.5.1. Assists the Wildfire Mitigation & Safety Engineer to achieve VM program requirements.
4.5.2. Assists in ensuring line inspection programs such as GO-165 Detailed Inspections, GO-165 Patrols, Third Party Patrols, LiDAR Surveys, Fly-over UAV Surveys, etc. are being conducted in compliance with CPUC regulations and BVES requirements and vegetation clearance discrepancies are being identified by the inspections.
4.5.3. Assists in reviewing the results of line inspection programs such as GO-165 Detailed Inspections, GO-165 Patrols, Third Party Patrols, LiDAR Surveys, Fly-over UAV Surveys, etc. and ensuring any vegetation discrepancies are tracked and resolved.
4.5.4. Assists in issuing or causing to be issued vegetation orders to the contractor.
4.5.5. Works closely in supporting CPUC audits, OEIS site visits, and other authorized agency reviews of vegetation management.

4.6. <u>GIS Specialist</u>**.** Supports the Wildfire Mitigation & Reliability Engineer in tracking vegetation clearance efforts and discrepancy management with the GIS and associated applications. Specifically:

4.6.1. Supports data entry and migration of contracted vegetation services and inspection programs into the GIS and associated applications.
4.6.2. Assists in scope of work development for RFPs regarding vegetation management service and inspection programs to ensure data and documentation requirements that are compatible with BVES GIS applications are accurately provided to bidders.
4.6.3. Assists in developing data reports and GIS overlays to support Management, OEIS, CPUC, CALFIRE, and other authorized agency reporting requirements.
4.6.4. Assists in developing overlays to support presentations and documents regarding the VM program.

4.7. <u>Customer Service Supervisor</u>**.** Works closely with the Wildfire Mitigation & Reliability Engineer on all customer issues regarding vegetation management. Specifically:

4.7.1. Coordinates responses to customer inquiries or disputes with the Wildfire Mitigation & Reliability Engineer.
4.7.2. Takes the lead on any customer complaints filed with the CPUC regarding vegetation management.
4.7.3. Supports customer outreach and education on vegetation management effort.

4.7.4. Ensures BVES Website and Social Media inform customers on where vegetation clearance work is being conducted on a weekly basis.

4.8. Customer Program Specialist**.** Supports the Wildfire Mitigation & Reliability Engineer on all customer outreach efforts. Specifically:

4.8.1. With input from the Wildfire Mitigation & Reliability Engineer, generates or updates customer outreach media products to educate customers on vegetation management efforts in the BVES service area.
4.8.2. BVES Website and Social Media inform customers on where vegetation clearance work is being conducted on a weekly basis.

4.9. Administrative Support Associate. Provides assistance in administering the VM program and VM QA/QC program. Specifically:

4.9.1. Provides administrative support as described in Section 5 for the VM QA/QC program.
4.9.2. Provides administrative support in the preparation and submission of reports and correspondence associated with the VM program.

5. Vegetation Quality Assurance/Quality Control Program:

5.1. Vegetation Management Quality Assurance Program. The VM QA program is the part of quality management focused on providing confidence that quality requirements will be fulfilled by the VM program. The confidence provided by quality assurance is twofold —internally to management and externally to customers, government agencies, regulators, certifiers, and other stakeholders. The VM QA program consists of the following elements:

- Annual VM Program Audit conducted by the Forester if assigned (if not assigned, the Regulatory Compliance Project Engineer will perform the audit).
- Quarterly VM Program Assessment conducted by the Wildfire Mitigation & Reliability Engineer.
- Periodic VM QC checks conducted by staff per this policy and procedure.

5.2. Annual VM Program Audit. The Annual VM Program Audit will be conducted by the Forester (if not assigned, the Regulatory Compliance Project Engineer will perform the audit) in January each year covering the previous calendar year.

5.2.1. The audit is intended to be a comprehensive review of the VM Program covering at a minimum the areas and questions specified in Appendix B, VM Program Annual QA Audit Areas. The annual audit report shall be due each year by January 31 to the Wildfire Mitigation & Reliability Engineer.
5.2.2. The audit report shall be routed to the President, Utility Manager, Utility Engineer & Wildfire Mitigation Supervisor, and the Field Operations Supervisor for review.
5.2.3. The Wildfire Mitigation & Reliability Engineer shall issue a report of corrective action on issues identified in the annual audit by May 1 each year if applicable.

5.3. Quarterly VM Program Assessment. The Quarterly VM Program Assessment is performed by the Wildfire Mitigation & Reliability Engineer according to the schedule in Table 5-1.

Table 5-1, Quarterly VM Assessment and Report Schedule

Period of Assessment and Report	Report Due Date
January 1 to March 31	April 15
April 1 to June 30	July 15
July 1 to September 30	October 15
October 1 to December 31	January 15

The Wildfire Mitigation & Reliability Engineer shall conduct the Quarterly VM Program Assessment and prepare a quarterly report on the VM Program to the President, Utility Manager, Utility Engineer & Wildfire Mitigation Supervisor, and the Field Operations Supervisor on the status of the program and its results. If assigned, the Forester shall assist in conducting the quarterly assessment and preparing the report.

5.3.2. The report shall include the following at a minimum:

- Brief narrative on the status of the VM program, VM QC Checks program and analysis or commentary on the metrics below as applicable.
- Number of trees trimmed as a result of the vegetation management program.
- Number of trees removed as a result of the vegetation management program.
- Number of Level 1 vegetation discrepancies identified.
- Number of Level 1 vegetation discrepancies resolved.
- Number of Vegetation Orders issued.
- Number of Vegetation Orders resolved.
- Any accidents, incidents, or near misses on the part of vegetation clearance personnel.
- Number of outages where vegetation made contact with power lines and caused the outage (break out those outages where vegetation clearance was in violation of standards)
- List of VM QC Checks performed (include name of evaluator and date performed).
- List of significant findings from VM QC Checks.
- Service area Map showing where contractor worked in the quarter and where contractor will work in the next quarter.
- Where the contractor is in the vegetation cycle plan (e.g., percent complete).
- Corrective action taken on issues noted in previous Quarterly VM Program Assessments.
- Other items that would be useful to Management regarding vegetation management.

5.4. Vegetation Management Quality Control Check Program. The VM QC Check program is designed to check compliance with VM standards in the field. In particular, the program should check VM clearance contractor work. The Wildfire Mitigation & Reliability Engineer will administer the program.

5.4.1. Table 5-2, VM QC Check Periodicities, lists the designated staff that shall be assigned VM QC Checks and the periodicity for the checks.

Table 5-2: VM QC Check Periodicities

Title	Periodicity
President	Once every two months (January, March, May, July, September, November)
Utility Manager	Once every two months (February, April, June, August, October, December)
Utility Engineer & Wildfire Mitigation Supervisor	Once every two months (January, March, May, July, September, November)
Field Operations Supervisor	Once every two months (February, April, June, August, October, December)
Regulatory Compliance Project Engineer	Once every two months (January, March, May, July, September, November)
Wildfire Mitigation & Reliability Engineer	Twice per month
Field Inspector	Twice per month
Forester (if assigned)	Twice per month

5.4.2. The Administrative Support Associate shall assign VM QC Checks using the VM QC electronic tracking application.

5.4.3. Evaluators assigned to perform VM QC Checks will be provided a map of the assigned circuit area for the QC Check by the Administrative Support Associate and a copy of the Appendix C VM QC Check Form. These may be provided through the electronic tracking program if equipped. Additionally, the flowchart for Trees and Major Limbs in Close Proximity to Bare Conductors of Appendix A will be made available to evaluators.

5.4.4. Evaluators will inspect the designated circuit for compliance with the VM standards per Section 3 of this policy and procedure and document the results on the VM QC map in accordance with the instructions on the VM QC Check Form of Appendix C. The evaluator will annotate the completed VM QC map with the evaluator’s name and date of the VM QC Check, sign the VM QC map, and route the VM QC map to the Wildfire Mitigation & Reliability Engineer. Additionally, the evaluator will update the VM QC Check Form of Appendix C – this may be done directly in the VM QC Check application if so equipped.

5.4.5. If an evaluator discovers a significant safety issue that would be classified as Level 1 per GO-95 Rule 18, the evaluator should immediately notify the Field Operations Supervisor or Field Inspector who will send the appropriate crew to resolve the issue in an expedient manner. If unable to reach the Field Operations Supervisor or Field Inspector, then notify the Service Crew or Dutyman to resolve the issue. Additionally, notify the Wildfire Mitigation & Reliability Engineer as soon as practical. Examples of Level 1 vegetation discrepancies are vegetation contacting, nearly contacting or arcing to high voltage conductor, vegetation contacting low voltage conductor and compromising structure, etc.

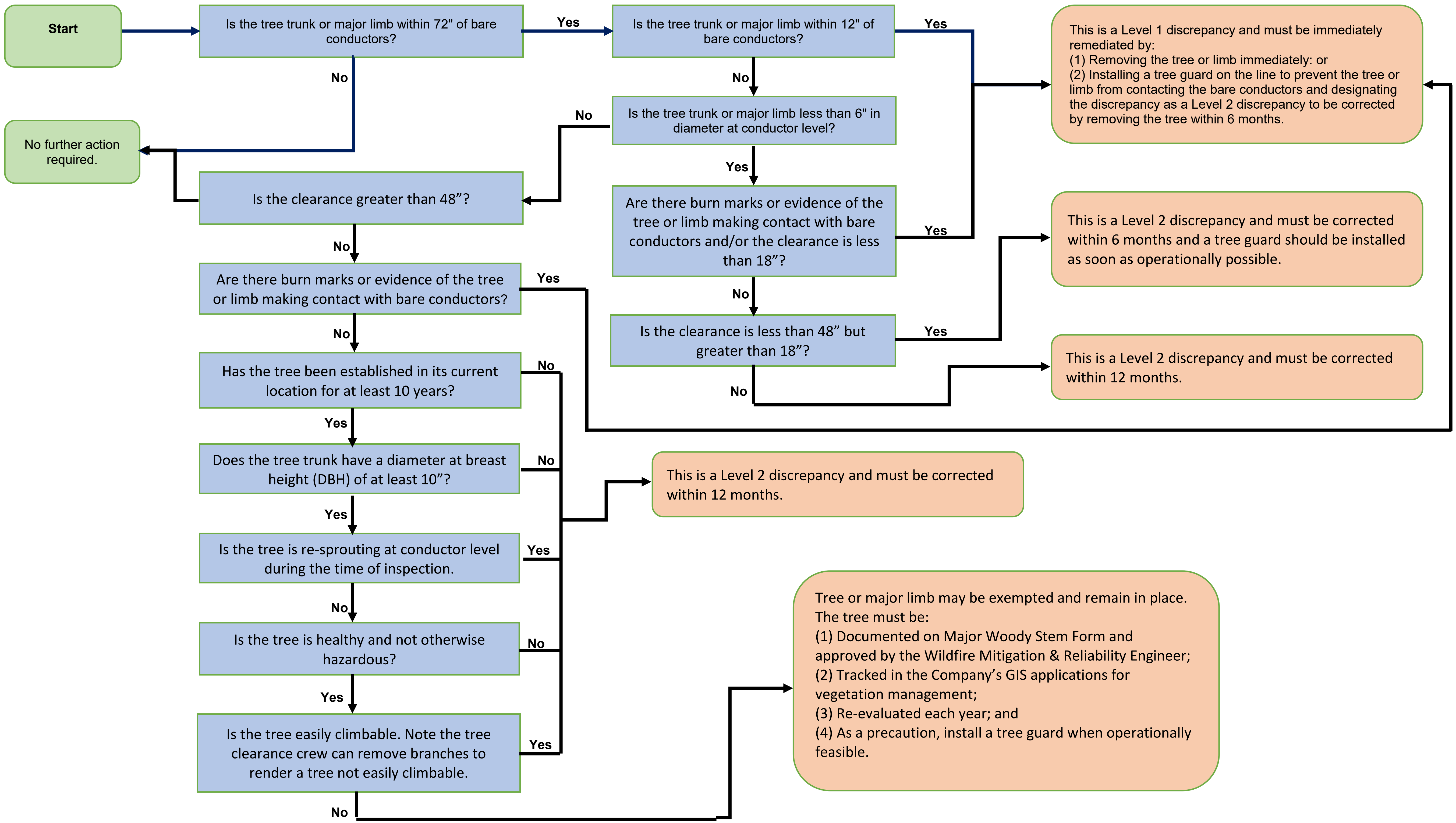
5.4.6. Completed VM QC Checks will be reviewed by the Wildfire Mitigation & Reliability Engineer. The Wildfire Mitigation & Reliability Engineer will issue vegetation orders as applicable to correct any discrepancies noted.

5.4.7. The Wildfire Mitigation & Reliability Engineer will also analyze the results of the VM QC Checks for trends and recommend corrective action to the Utility Manager if deemed necessary. This analysis shall be included in the Quarterly VM Program Assessment report.

5.4.8. The Administrative Support Associate shall check that assigned VM QC checks are being performed in a timely manner and send reminders to individuals alerting them if a VM QC check is overdue.

5.4.9. The VM QC electronic tracking application shall be used, if available, to maintain a record of the VM QC checks, track correction of vegetation orders, and perform program analysis.

Appendix A
Trees and Major Limbs in Close Proximity to Bare Conductors



Appendix B

VM Program Annual QA Audit Areas	
VM Line Clearance	Is the VM program effective at ensuring vegetation meets required clearance specifications?
	Is the VM program on track with the programmed schedule?
	Is the VM program effective in reducing vegetation contact with bare conductors?
	Are any changes to the VM clearance standards delineated in Section 3 necessary?
	Is the VM clearance contractor(s) executing work in accordance with the VM contract(s)?
	Are changes to the VM Contract Scope of Work needed?
VM Inspections	Are VM inspections (patrol, detailed, LiDAR, etc.) being conducted in accordance with the Company's effective Wildfire Mitigation Plan?
	Are the results of VM inspections being documented, tracked, and resolved in a timely manner in accordance with GO-95 Rule 18?
	For each type of inspection performed, assess whether or not the inspection is effective and useful to assisting in achieving VM program objectives?
	Should additional inspections be performed?
	Is the scheduling of inspections appropriate or should the schedule be modified?
VM QC Checks	Are VM QC Checks being performed in accordance with the requirements of this policy and procedure (Section 5.3)?
	Are personnel performing VM QC Checks sufficiently knowledgeable and qualified to perform the checks?
	Are VM QC Checks documented?
	Are discrepancies identified in VM QC checks being tracked and resolved in a timely manner in accordance with GO-95 Rule 18?
	Are VM QC Checks effective at identifying vegetation clearance issues?
	Should modifications to Appendix B VM QC Check Instructions be made?
VM Quarterly Reports	Are the VM Quarterly Reports being conducted per Section 4.1.24?
	Are the VM Quarterly Reports useful in providing management an assessment of the VM program?
	Should changes be made to the content and/or periodicity of the VM Quarterly Reports?
VM Program	Overall, were the Company's VM Program objectives achieved?
	Are changes recommended to the VM Program Policy and Procedures?
	Are changes in the Company's execution of its VM Program warranted?

Appendix C
Vegetation Management Quality Control Form

The VM QC Evaluator shall print the QC map and indicate the location of each discrepancy noted by indicating the discrepancy “type” and an arrow showing the approximate location on the map.

Note: Discrepancies of a significant safety nature that would be classified as Level 1 per GO-95 Rule 18 should be resolved immediately by notifying the Field Operations Supervisor or Field Inspector who will send the appropriate crew to resolve the issue in an expedient manner. If unable to reach the Field Operations Supervisor or Field Inspector, then notify the Service Crew or Dutyman to resolve the issue.

Examples of Level 1 vegetation discrepancies are vegetation contacting, nearly contacting or arcing to high voltage conductor, vegetation contacting low voltage conductor and compromising structure, etc.

The QC Evaluator shall indicate the total number of discrepancies for each type on this form. Upon completion of the QC, the QC Evaluator shall update the online QC form, sign and date the map, and return the map to Wildfire Mitigation & Reliability Engineer.

Discrepancy Types:

Type 1: Any vegetation that is within 72” from primary conductors. **Total #:** _____

Type 2: Trimmed vegetation that is not trimmed to a minimum of 12’ from primary conductors. **Total #:** _____

Type 3: Any instances of fast growing trees (poplar, aspen, cottonwood) that were not trimmed out to 12' regardless of proximity to line. **Total #:** _____

Type 4: Any instances of vertical coverage above BVES sub-transmission lines (34.5 kV). **Total #:** _____

Type 5: Tree and Major Limb infractions: See Trees and Major Limbs in Close Proximity to Bare Conductors flowchart. **Total #:** _____

Type 6: Any tree that is dead, rotten or diseased, or portions of otherwise healthy trees, which overhang or lean toward and may fall into a span of power lines. Note that this may apply to trees outside the clearance zone. **Total #:** _____

Total # of discrepancies: _____

Comments:

____

____

____

____

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