Bear Valley Electric Service 2023-2025 Wildfire Mitigation Plan

2023 Revision 0

Submitted by:

Bear Valley Electric Service, Inc.

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1. Executive Summary

In the opening section of the WMP, the electrical corporation must provide an executive summary that is no longer than 10 pages. The executive summary must provide brief narratives on each of the following topics.

The Bear Valley Electric Service, Inc. (BVES or Bear Valley) Wildfire Mitigation Plan (WMP) aims to reduce the risk of utility-caused ignitions or threats as well as to mitigate the need for public safety power shutoff (PSPS) events in the future. This WMP represents BVES's plan to continue to reduce utility wildfire risks, maintain reliability, meet its regulatory obligations, and plan for continuous improvement through future years within the WMP compliance cycle.

Bear Valley's service area is in the mountain resort community of Big Bear Lake, California, with approximately 24,650 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 Utility Commission (CPUC) General Order 95 (GO 95). The adjacent wilderness environment, including heavily forested terrain with dense underbrush 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 result 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 90% in Tier 2 (elevated risk) and the remaining 10% in Tier 3 (extreme risk) areas. The California Department of Forestry and Fire Protection ("Cal Fire") California Fire Hazard Severity Zone Map Update Project rates Bear Valley's service area as "Very High Fire Hazard Severity Zone". Years of drought and elevated ambient temperatures above historical norms has only exacerbated the situation further. Climate change predictions project increased drought, dryness, and elevated temperatures will continue on their increasing trends. It is against this backdrop that BVES develops its WMP initiatives.

This WMP demonstrates the continued effort and investment underway at BVES and progress realized to reduce the probability of utility-caused ignitions and reduce the potential of wildfires to impact the reliable operation of the BVES system. The 2023-2025 WMP includes more data and quantitative content than its previous submissions and incorporates longer-term systematic thinking on reducing wildfire risks, additively and cumulatively, to improve BVES's wildfire mitigation maturity over time.

1.1 Summary of 2020–2022 WMP Cycle

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

BVES did not experience any ignition events or conditions that would have caused it to activate any Public Safety Power Shutoff (PSPS) to mitigate wildfire threats during the 2020-2022 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.

Despite an absence of utility caused ignitions or PSPS events, BVES recognizes the risk of ignitions and PSPS events is still significant and, therefore, embraces wildfire safety as a core competency in executed 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, wildfires, and avoid reliance on PSPS as an ignition mitigation tool.

During the 2020-2022 WMP Cycle, BVES achieved substantial progress on all 10 categories of its WMP initiatives. Some of the more significant achievements are highlighted as follows:

1. **Risk Assessment and Mapping:** BVES conducts its overall risk-based decision making in accordance with CPUC Decision D.19-04-020 of May 6, 2019, which provides the framework that the Small and Multi-jurisdictional Utilities (SMJUs) are required to follow. This approach to risk management includes some of the basic tenets of the International Standardization Organization's "Risk Management – Principles and Guidelines" ("ISO 31000"). BVES found that this approach is heavily reliant on subject matter experts (SMEs) and is not sufficiently granular to permit detailed prioritization of specific circuits, segments and areas for risk mitigation initiatives.

   In order to implement a method to assess risk at the circuit level and prioritize initiatives on the BVES sub-transmission and distribution system, BVES implemented the Fire Safety Circuit Matrix. This rudimentary model determines circuit-level risk under current and planned mitigation activities intended to reduce ignition potential. The purpose of the Fire Safety Circuit Matrix model is to assist as a planning tool in determining a circuit-level risk that accounts for the current and planned mitigation activities that intend to reduce ignition potential. The Fire Safety Circuit Matrix was utilized to inform the planning period of the WMP considering changes to the risk profile as mitigations are executed over time. Outputs (mitigations and controls) from the risk-based decision-making approach are integrated in the Fire Safety Circuit Matrix to establish where and in what sequence the mitigations or controls should be applied to the sub-transmission and distribution systems. BVES updates this model on a semi-annual basis as initiative targets are reviewed and revisited for the following year. The model was improved to use historical weather data and vegetation density (based on LiDAR surveys) in order to determine the risk of wildfire and reduce reliance on SME evaluation.

   In 2021, the utility contracted expert services to enhance current risk maps and expand its capability to better predict fire conditions and behaviors. The model aimed to address four separate subtasks of the Risk Mapping Program: (1) ignition probability mapping showing the probability of ignition along overhead electric lines and equipment; (2) match drop simulations showing the potential wildfire consequence of ignitions that occur along electric lines and equipment under current (2021) conditions; (3) match drop simulations showing the potential wildfire consequence of ignitions that occur along the electric lines and equipment under future (2050) conditions; and (4) summarized risk maps showing overall ignition probability and estimated wildfire risk under current and future conditions. BVES's modeling package accounts for ignition risk probability and wildfire consequence (both area burned and structures impacted) through climate-driven factors. The visuals present a guide, which influences future planning targeting areas of greatest risk.

In June of 2022, BVES contracted with Technosylva, an expert wildfire risk modeling consultant firm, to further advance the Risk Mapping Program and enhance situational awareness. Better understanding of the risk environment will improve BVES's resource allocation. This effort leveraged Technosylva's Wildfire Analyst Enterprise (WFA-E) software capabilities and solutions implemented across California for other electric utility companies. Engaging with Technosylva has provided BVES software applications and analysis to generate the following:

- Through use of WFA-E FireSim, provision of on-demand, real time wildfire behavior modeling, predictive spread conditions, and derivation of potential impacts analysis
- Ability to conduct simulations on-demand, to reflect changing conditions or local data observations, including proactive "what if" scenarios
- Weather and wildfire risk forecasting for customer assets and the service territory using daily weather prediction integration to support PSPS activation calls and response operations
- Asset risk analysis using historical weather climatology to support WMP development and mitigation planning

The asset risk analysis will utilize Technosylva's Wildfire Risk Reduction Model (WRRM) which uses historical climatology (weather & fuel moisture data) as key input weather scenarios (~ 30 year and 2 km hourly re-analysis data). The model produces risk metrics by running fire spread simulations for each weather scenario territory wide. The outputs can be aggregated based on percentile and assigned to assets. The model uses historical or predicted fuels data (2030 etc.) and utilizes hundreds of millions of fire spread simulations across customer service territory. The outputs are to be used to support mitigation planning in addition to setting context for daily FireCast asset risk forecasts.

It is BVES's intent to transition from using the Fire Matrix to use the WRRM to prioritize its WMP initiatives. The first runs of the WRRM were not completed in time to inform the 2023 WMP grid hardening work plan, since much of the planning had to occur in the summer of 2022 so that design specifications could be identified sufficiently in advance due to the long procurement supply chain process that all utilities are currently experiencing. Initial WRRM results became available to BVES in late February 2023. Therefore, the WRRM will be used in the 2024 and 2025 WMP Updates. BVES believes that replacing the Fire Matrix with the WRRM will provide a probabilistic model and the level of granularity will eventually shift from the circuit level to the segment or span level. The model will provide calculated probability, consequence, and risk.

2. **Situational Awareness and Forecasting:** BVES installed 20 weather stations, which it continuously monitors. The weather stations record weather data in a historian and the

outputs are utilized by BVES's weather consultant, Technosylva's models, and are available to open-source forecasting (NOAA). Additionally, BVES worked with stakeholders to ensure the HD ALERTWildfire Network had sufficient cameras (15 total in 7 locations) to provide full visibility into the Big Bear Valley. As discussed above, during this period, BVES implemented Technosylva's Wildfire Analyst Enterprise (WFA-E) software capabilities and solutions to provide real time fire threat forecasts along BVES's circuits. This capability has enhanced BVES's ability to evaluate the potential for invoking Public Safety Power Shutoffs (PSPS).

BVES also began installing additional fault indicators (FIs) in its system. FIs are installed at specific distances along a circuit and at major branch lines so that when a fault occurs, the fault zone (where the fault occurred) is minimized, thereby reducing time to locate and identify the fault and, therefore, restore service to affected customers. BVES already had 110 FIs in its system. In 2022, BVES installed 99 FIs under this initiative and will install an additional 30 FIs in 2023 to complete the project.

Mid-2022, BVES initiated a pilot program to install an Online Diagnostic System, which uses continuous monitor sensors to provide usable grid insight information that is measured, reported, and documented, on one of its circuits. 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. Bear Valley anticipates completing this pilot project in 2023.

3. **Grid Design and System Hardening:** Bear Valley achieved a significant amount of system hardening to mitigate ignitions, reduce consequence of wildfires, and minimize PSPS event impacts during the 2020-2022 WMP period. By the end of 2022, BVES achievements included the following:

- Completed a covered conductor pilot program (finished in 2020), which evaluated various covered conductor products.
- Replaced of 30.2 bare wire circuit miles with covered conductors.
- Replaced all expulsion fuses (a total of 3,114) with 2,578 current limiting fuses and 536 electronic fuses.
- Completed technical and safety updates to the Pineknot Substation
- Completed technical and safety updates to the Palomino Substation.
- Completed its evacuation route hardening pilot program, which validated the installation and efficacy of wire mesh wrap, fire resistant composite pole, and lightweight steel poles.
- Hardened all three primary evacuation routes to the Big Bear Lake and Big Bear City areas by installing a wire mesh wrap on 997 wood poles.
- Assessed a total of 3,641 poles.
- Replaced or remediated a total of 1,340 poles.
- Removed 644 tree attachments (563 remain to be removed).

- Installed a fiber optic network in its service area that will serve at the backbone for significant grid automation and situational awareness projects to enhance protective systems for safety and provide grid resiliency.
- Installed Fault Localization Isolation and Service Restoration (FLISR) system on its sub-transmission system.
- Replaced its three primary sub-transmission system auto-reclosures with Pulse Condition IntelliRupters.
- Connected into SCADA via the fiber network and automated three substations.

Bear Valley's plan to replace the Radford Line, a bare wire sub-transmission line that operates at 34.5 kV with a capacity of 8 MW and consists of 95 wood poles, with high-performance covered conductor and fire resistant (ductile iron) poles because it is located in the HFTD 3 (extreme fire risk), was not completed during this WMP cycle due to the US Forest Service (USFS) not yet approving the permit. The project is delayed and BVES is working with the USFS to gain approval of the project and currently projects completing the project in 2024.

These grid hardening efforts have reduced the risk of ignitions, consequences of wildfires, risk of invoking PSPS, impact of potential PSPS events, and built a strong foundation for further grid design and hardening efforts in BVES's next WMP cycle.

4. **Asset Management and Inspections:** During this WMP cycle, Bear Valley introduced a number of advance technology inspection techniques beyond those required by GO-165 inspection compliance requirements (Detailed Inspections, Patrol Inspections, and Intrusive Pole Inspections).

BVES established the following highly effective state-of-the-art inspection programs:

- Annual LiDAR surveys of all overhead circuits in its service area.
- Annual UAV HD photography and videography of all overhead circuits in its service area.
- Annual UAV thermography of all overhead circuits in its service area.
- Annual independent third-party patrol inspection of all overhead circuits in its service area.

Bear Valley also initiated a formal asset management quality assurance and quality control program aimed at grid hardening work as well as asset inspections. Additionally, BVES significantly upgraded its asset management enterprise system in terms of capability, geospatial data, and staff training on employing the system to enhance asset management activities.

5. **Vegetation Management and Inspections:** During the 2020-2022 WMP cycle, Bear Valley focused on executing its enhanced vegetation management program, removing hazard-threat trees, introducing a number of advance technology state-of-the-art inspection techniques beyond those required by GO-165 inspection compliance requirements (Detailed Inspections and Patrol Inspections). The following are some highlights of vegetation management achievements:

- Annual LiDAR surveys of all overhead circuits in its service area.
- Annual UAV HD photography and videography of all overhead circuits in its service area.

- Annual independent third-party patrol inspection of all overhead circuits in its service area.
- Established having a fulltime contracted forester on staff.
- Removed 432 hazard-threat trees.
- Trimmed 18,417 trees to enhanced vegetation management specifications.
- Performed 270 vegetation management quality checks.
- Performed 10 vegetation management audits.

In 2020, vegetation density within a 24-foot corridor along all overhead ("OH") lines was 25.44 percent as measured by LiDAR surveys. In 2022, the vegetation density was 20.17 percent, indicating that the overall density of vegetation along BVES's lines have been reduced by 20.7 percent.

Bear Valley also improved its formal quality assurance and quality control program aimed at vegetation management work as well as vegetation management inspections. Additionally, BVES significantly upgraded its vegetation management enterprise system in both terms of capability, geospatial data, and staff training on employing the system to enhance asset management activities.

6. **Grid Operations and Operating Protocols:** BVES developed and implemented operational changes based on weather conditions to reduce the risk of ignitions. The operational changes are escalatory, with the invoking of a PSPS as the action of last resort. BVES determined that during high fire threat weather, it is prudent and efficient for BVES to suspend work, by BVES staff or its contractors that might produce sparks or create fire hazards. Due to BVES's small size, BVES and its contractors are able to pivot to other low risk work during such conditions. Bear Valley refined its protocols for re-energization following a PSPS event to restore service in a safe and as rapid manner. Staff were trained on these protocols which were exercised during functional and table-top exercises for PSPS events. BVES also determined the areas most likely to experience a PSPS event during high threat fire weather conditions. BVES then developed the ability to isolate these areas from its system such that only customers in these high-risk areas would be impacted by a PSPS event.

7. **Data Governance:** BVES made significant progress in migrating its many data-bases, which were mostly in spreadsheets, to a centralized geographic data repository. BVES engaged the support of a consultant to identify gaps and make recommendations for methods to address its GIS process and to immediately update the records in the required format. This initiative resulted in developing a common data definition, increase digitization of field work activities, and update system interfaces to automate data flow into GIS for Energy Safety reporting. Using the Energy Safety GIS Data Reporting Requirements and Schema as a guide, initial data governance steps were taken to define the system of record and assessing initial data quality for each of the required feature datasets in the OEIS schema.

8. **Resource Allocation Methodology:** As previously discussed, BVES conducts its overall risk-based decision making in accordance with CPUC Decision D.19-04-020 of May 6, 2019, which provides the framework that the Small and Multi-jurisdictional Utilities (SMJUs) are required to follow. Using this framework BVES calculated Risk Spend Efficiencies (RSEs) and utilized the RSEs in the initiative selection process. BVES was able to successfully

allocate sufficient resources to achieve WMP initiatives. No WMP initiatives during this period were not achieved as a result of inadequate resourcing.

9. **Emergency Planning and Preparedness:** During this WMP cycle, BVES updated its Emergency and Disaster Response Plan (EDRP) and its PSPS Procedures. Additionally, BVES worked with stakeholders to improve coordination on PSPS and emergency response. BVES conducted PSPS table-top exercises and functional drills with excellent stakeholder participation. Also, BVES took a number of effective steps to ensure its workforce is well positioned to conduct restoration efforts. Additionally, BVES established routine briefings for the public and local government, agencies and other key stakeholders (utilities, communications companies, etc.) to better coordinate emergency planning and preparedness. BVES also implemented a survey program to assess the effectiveness of its outreach programs so that it may improve its messaging. During this period, BVES established special customer service and assistance procedures to assist customers during any wildfire recovery.

10. **Stakeholder Cooperation and Community Engagement:** BVES developed a comprehensive community outreach program and made significant efforts to identify and engage key community stakeholders. These programs are maturing and will serve BVES well in further advancing its outreach programs and coordination with stakeholders. BVES developed and implemented a plan to better service Access and Functional Needs (AFN) customers in the event of a PSPS and made significant progress in identifying AFN customers. Additionally, BVES has put in place a process to identify AFN customers during new customer sign up and periodically throughout the year because the AFN population is not static. BVES has identified all key stakeholders including those that own and operate critical infrastructure and has developed primary, secondary, and tertiary points of contact.

BVES also implemented a Stakeholder Portal on its website to communicate more efficiently with stakeholders during PSPS events. BVES engaged with other utilities outside California on best practices and cooperation on wildfire mitigation and PSPS issues. This has been done primarily through participation at several major transmission and distribution (T&D) conferences. Additionally, BVES has provided other utilities outside of California information on wildfire mitigation initiatives upon request. BVES has been coordinating with various stakeholders for years including BBFD, CAL FIRE, the USFS, county fire authorities, mutual aid organizations and more. BVES improved information sharing and coordination with these organizations and others. BVES implemented an initiative that provides BBFD, Sheriff, and CHP the iRestore App, which enables first responders to report directly into BVES's dispatch using their mobile devices (phone) with a picture of the situation and the geo-coordinates for the location. By reporting this way, BVES will have the phone number of the first responder making the report and BVES dispatch will be able to discuss the issue further with the first responder.

1.2 Summary of 2023–2025 Base WMP

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

The primary objective of the WMP is to ensure that BVES constructs, maintains, and operates its electric lines and equipment in a manner that minimizes the risk of catastrophic wildfire posed by and to its lines and equipment. Additionally, the WMP helps to ensure BVES is compliant with all applicable regulations and statutes. Finally, an objective of the WMP is to assist BVES in its goal to continue to provide customers with safe delivery of service at competitive rates and maintain its role as a valued partner in the community it serves by promoting public safety.

BVES's WMP aims to reduce threats of utility-caused wildfires by eliminating sources of ignition and, in the event of a wildfire affecting the BVES service area, to provide emergency response and restoration actions regardless of cause. Another objective of BVES's WMP is to minimize the need to activate disruptive PSPS events. BVES seeks to fulfill the requirements detailed in PUC Section 8386 and associated statutes by identifying wildfire risks and risk drivers within the BVES service territory; providing an overview of strategies, protocols, plans, and programs to mitigate wildfires; tracking metrics to monitor performance of the WMP's initiatives; ensuring the performance of quality control and assurances of completed work; and setting forth protocols for communicating with customers and public-safety partners throughout wildfire mitigation, PSPS, and emergency events. The following objectives are categorized by timeframe: objectives to accomplish within the next three years and within the next ten years.

The following summarize Bear Valley's three-year objectives for the 2023-2025 WMP:

- Replace all sub-transmission (34.5 kV) overhead bare conductors with covered conductors. Complete the Radford Line Replacement Project.
- Assess and remediate all sub-transmission (34 kV) poles.
- Harden secondary evacuation routes in highest risk areas.
- Remove all tree attachments from high-risk areas.
- On a priority basis, automate substations, switches, field devices, and fuse TripSavers and connect to SCADA.
- Replace capacitor banks and connect to SCADA.
- Pursue development and execution of the Bear Valley Solar Energy Project.
- Pursue development and execution of the Bear Valley Energy Storage Project.
- Upgrade highest risk substations.
- Continue robust asset inspection routine of annual Detailed Inspections, Patrol Inspections, LiDAR surveys, UAV HD photography & thermography, 3rd party ground patrols, intrusive pole testing, and substation inspections.
- Implement robust asset management and inspection enterprise system.
- Improve quality assurance and quality control program on asset work and asset inspection.
- Continue robust vegetation inspection routine of annual Detailed Inspections, Patrol Inspections, LiDAR surveys, UAV HD photography & thermography, 3rd party ground patrols, intrusive pole testing, and substation inspections.
- Implement robust vegetation management and inspection enterprise system. Ensure all trees within the right of way are tracked in the data system.
- Improve quality assurance and quality control program on vegetation management inspection and clearance work and asset inspection.

- Develop and implement program to promote vegetation communities that are sustainable, fire-resilient, and compatible with the use of the land as an electrical corporation right-of-way.
- Complete online diagnostic pilot program and evaluate effectiveness.
- Complete installation of fault indicators (FIs). Evaluate need for additional FIs.
- Evaluate need for additional weather stations.
- Evaluate need for additional HD Alert Cameras.
- Develop and implement Fire Potential Index.
- Improve staff proficiency in utilizing advanced fire threat weather forecasting tools.
- Improve staff training on emergency and disaster response plan through a combination of classroom instruction, tabletop exercises, and functional drills.
- Increase coordination with community stakeholders in emergency response.
- Develop robust lines and layers of communications with stakeholders and customers.
- Integrate plan to restore service after an outage due to a wildfire or PSPS event.
- Establish strong programs, systems, and protocols to support residential and non-residential customers in wildfire emergencies and PSPS events.
- Continue to deploy and improve 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. Evaluate effectiveness of outreach efforts.
- Continue to improve program to understand, evaluate, design, and implement wildfire and PSPS risk mitigation strategies, policies, and procedures specific to access and functional needs customers. Evaluate effectiveness of these efforts.
- Work with stakeholders to develop and integrate plans, programs, and 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. Evaluate effectiveness of these collaborative efforts.
- Continue to be proactive in sharing and integration of best practices and collaborating with other electrical corporations on technical and programmatic aspects of WMP programs.

The following summarize Bear Valley's ten-year objectives for the 2023-2025 WMP:

- Replace all high and medium risk distribution (4 kV) overhead bare conductors with covered conductors.
- Assess and remediate all high and medium risk distribution (4 kV) poles.
- Harden secondary evacuation routes.
- Remove all tree attachments from distribution system.
- Automate remaining substations, switches, field devices, and fuse TripSavers and connect to SCADA.
- Replace remaining capacitor banks and connect to SCADA.

- Pursue other renewable generating facility opportunities.
- Pursue other energy storage project opportunities.
- Assess emerging technologies aimed at early detection of asset degradation, wire down detection, and other ignition prevention/mitigation technologies.
- Assess other emerging sub-transmission and distribution inspection techniques.
- Implement social media and other effective platforms to increase 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. Evaluate effectiveness of these outreach efforts.
- Establish streamlined routine for sharing lessons learned and best practices among peers.
- Continue to conduct program to promote vegetation communities that are sustainable, fire-resilient, and compatible with the use of the land as an electrical corporation right-of-way.
- Evolve vegetation inspection cycles to be risk based.
- Evolve vegetation clearance cycles to be risk based.
- Evaluate effectiveness of installing cameras, infrared detectors, LiDAR instruments, and other technologies on overhead assets to provide remote monitoring.
- Integrate EDRP with stakeholder emergency response plans.
- Evaluate increased use of social media and technology to improve and streamline communications with stakeholders and customers.
- Implement social media and other effective platforms to increase 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. Evaluate effectiveness of these outreach efforts.
- Establish streamlined routine for sharing lessons learned and best practices among peers.

BVES recognizes there is still substantial work to be performed in wildfire mitigation and room for improvement and, therefore, has developed its 2023-2025 WMP to continue to make substantial progress in wildfire mitigation and address areas of weakness.

2. Responsible Persons

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

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

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

Executive-Level Owner with Overall Responsibility

The following Executive Level contact is ultimately responsible for monitoring and execution of the BVES WMP:

Name and title: **Paul Marconi, President, Treasurer, & Secretary BVES** is responsible for the overall management of BVES and is directly responsible for ensuring all WMP elements are executed as intended. The President, Treasurer, & Secretary shall provide the Board of Directors' Safety and Operations Committee periodic updates on safety issues, plan execution; identify any problems, delays in schedule, and resource shortfalls; and propose solutions to issues and problems. The President, Treasurer & Secretary shall also keep the Vice President, Regulatory Affairs of Golden States Water Company (GSWC) informed of all compliance and regulatory affairs issues regarding the plan. The President, Treasurer, & Secretary shall communicate the WMP to BVES staff and hold staff accountable for executing their portions of the WMP including PSPS activation decisions. The President, Treasurer, & Secretary shall ensure the applicable portions of the WMP is communicated to local government and agencies, key stakeholders, customers, and the public. The President, Treasurer, & Secretary is responsible for ensuring lessons learned and metrics from the current WMP are incorporated into future WMPs as appropriate.

Program Owners Specific to Each Section of the Plan

Key utility staff execute and implement this WMP working closely with public safety, local agencies and governments, fire, forestry management, first responders, and customers to enable information dissemination to vested stakeholders. BVES also retains experienced and qualified third-party contractors to assist in the performance of the WMP. Table 2-1 outlines leadership roles regarding implementation and monitoring of the WMP and their relevant responsibilities.

Table 2-1 WMP Responsible Persons

Name	Title	Email	Phone Number	Component
Section 1: Executive Summary				
Paul Marconi	President, Treasurer, & Secretary	Paul.Marconi@bvesinc.com	909.866.4678 x100 909-202-9539	Entire Section

Section 2: Responsible Persons				
Jon Pecchia	Utility Manager	Jon.Pecchia@bvesinc.com	909.866.4678 x102 909.253.8966	Entire Section
Section 3: Statutory Requirement Checklist				
Jon Pecchia	Utility Manager	Jon.Pecchia@bvesinc.com	909.866.4678 x102 909.253.8966	Entire Section
Section 4: Overview of WMP				
Paul Marconi	President, Treasurer, & Secretary	Paul.Marconi@bvesinc.com	909.866.4678 x100 909-202-9539	Entire Section
Section 5: Service Territory				
Tom Chou	Utility Engineer & Wildfire Mitigation Supervisor	Tom.Chou@bvesinc.com	909.273.8009	Section 5.1 - 5.2
Jared Hennen	Fire Mitigation & Reliability Engineer	Jared.Hennen@bvesinc.com	909.255.2948	Section 5.3
Jon Pecchia	Utility Manager	Jon.Pecchia@bvesinc.com	909.866.4678 x102 909.253.8966	Section 5.4
Section 6: Risk Methodology ad Assessment				
Paul Marconi	President, Treasurer, & Secretary	Paul.Marconi@bvesinc.com	909.866.4678 x100 909-202-9539	Entire Section
Section 7: Wildfire Mitigation Strategy and Development				
Paul Marconi	President, Treasurer, & Secretary	Paul.Marconi@bvesinc.com	909.866.4678 x100 909-202-9539	Entire Section
Section 8: Wildfire Mitigations				
Paul Marconi	President, Treasurer, & Secretary	Paul.Marconi@bvesinc.com	909.866.4678 x100 909-202-9539	Entire Section
Tom Chou	Utility Engineer	Tom.Chou@bvesinc.com	909.273.8009	Section 8.1
Jared Hennen	Reliability Engineer	Jared.Hennen@bvesinc.com	909.255.2948	Section 8.2
Jon Pecchia	Utility Manager	Jon.Pecchia@bvesinc.com	909.866.4678 x102 909.253.8966	Section 8.4

Sean Matlock	Energy Resource Manager	Sean.Matlock@bvesinc.com	909.522.1913	Section 8.5
Section 9: Public Safety Power Shutoff				
Sean Matlock	Energy Resource Manager	Sean.Matlock@bvesinc.com	909.522.1913	Entire Section
Section 10: Lessons Learned				
Paul Marconi	President, Treasurer, & Secretary	Paul.Marconi@bvesinc.com	909.866.4678 x100 909-202-9539	Entire Section
Section 11: Corrective Action Program				
Jon Pecchia	Utility Manager	Jon.Pecchia@bvesinc.com	909.866.4678 x102 909.253.8966	Entire Section
Section 12: Notices of Violation and Defect				
Jon Pecchia	Utility Manager	Jon.Pecchia@bvesinc.com	909.866.4678 x102 909.253.8966	Entire Section

3. Statutory Requirement Checklist

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

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

BVES affirms its WMP addresses each statutory requirement in accordance with Public Utilities Code section 8386(c). Table 3-1 provides a checklist of each statutory requirement BVES must adhere to. References to relevant hyperlinks and page numbers within the WMP are provided for each statutory requirement in the table below.

Table 3-1 Statutory Requirements Checklist

PUC Section 8386	Description	WMP Section
(a)	Each electrical corporation shall construct, maintain, and operate its electrical lines and equipment in a manner that will minimize the risk of catastrophic wildfire posed by those electrical lines and equipment.	Section 5 Section 7
(b)	Each electrical corporation shall annually prepare and submit a wildfire mitigation plan to the Wildfire Safety Division for review and approval. The plan shall cover at least a three-year period.	Section 1
(c) (1)	Provide list of persons responsible for executing the WMP and each members responsibility in the process.	Section 2
(c) (2)	The objectives of the WMP	Section 4.1
(c) (3)	A description of the preventative strategies and programs to be adopted by BVES to minimize the risk of its electrical lines and equipment causing catastrophic wildfires, including consideration of dynamic climate change risks.	Section 6 Section 7

(c) (4)	A description of the metrics BVES plans to use to evaluate the plan's performance and the assumptions that underlie the use of those metrics.	Section 6
(c) (5)	A discussion of how the application of previously identified metrics to previous plan performances has informed the plan.	Section 6 Section 8 Section 11
(c) (6)	A description of BVES's protocols for disabling reclosers and deenergizing portions of the electrical distribution system that consider the associated impacts on public safety. As part of these protocols, each electrical corporation shall include protocols related to mitigating the public safety impacts of disabling reclosers and deenergizing portions of the electrical distribution system that impacts critical first responders.	Section 8
(c) (7)	A description of BVES's appropriate and feasible procedures for notifying a customer who may be impacted by the deenergizing of electrical lines, including procedures for those customers receiving medical baseline allowances. The procedures shall direct notification to all public safety offices, critical first responders, health care facilities, and operators of telecommunications infrastructure with premises within the footprint of potential de-energization for a given event. The procedures shall comply with any orders of the commission regarding notifications of de-energization events.	Section 9

(c) (8)	Identification of circuits that have frequently been deenergized pursuant to a de-energization event to mitigate the risk of wildfire and the measures taken, or planned to be taken, by BVES to reduce the need for, and impact of, future de-energization of those circuits, including, but not limited to, the estimated annual decline in circuit de-energization and de-energization impact on customers, and replacing, hardening, or undergrounding any portion of the circuit or of upstream transmission or distribution lines.	Section 4 Section 8 Appendix C.5.5.1
(c) (9)	Plans for vegetation management.	Section 7 Section 8
(c) (10)	Protocols for the PSPS of BVES's transmission infrastructure, etc.	Section 5
(c) (11)	A description of BVES's protocols for the de-energization of BVES's transmission infrastructure, for instances when the de-energization may impact customers who, or entities that, are dependent upon the infrastructure. The protocols shall comply with any order of the commission regarding de-energization events.	Section 4 Section 8
(c) (12)	A list that identifies, describes, and prioritizes all wildfire risks, and drivers for those risks, throughout BVES's service territory such as those risks and risk drivers associated with design, construction, operations, and maintenance of BVES's equipment and facilities as well as risks and risk drivers associated with topographic	Section 7 Section 8

	and climatological risk factors.	
(c) (13)	A description of how the plan accounts for the wildfire risk identified in BVES's Risk Assessment Mitigation Phase filing.	Section 6 Section 7
(c) (14)	A description of the actions BVES will take to ensure its system will achieve the highest level of safety, reliability, and resiliency, and to ensure that its system is prepared for a major event, including hardening, and modernizing its infrastructure with improved engineering, system design, standards, equipment, and facilities, such as undergrounding, insulating of distribution wires, and replacing poles.	Section 5 Section 8
(c) (15)	A description of where and how BVES considered undergrounding electrical distribution lines within those areas of its service territory identified to have the highest wildfire risk in a commission fire threat map.	Section 5
(c) (16)	A showing that BVES has an adequately sized and trained workforce to promptly restore service after a major event, taking into account employees of other utilities pursuant to mutual aid agreements and employees of entities that have entered into contracts with BVES.	Section 7 Section 8
(c) (17)	Identification of any geographic area in BVES's service territory that is a higher wildfire threat than is currently identified in a commission fire threat map, and where the commission should consider expanding the high fire threat district	

	based on new information or changes in the environment.	
(c) (18)	Methodology for identifying and presenting enterprise-wide safety risk and wildfire-related risk that is consistent with other electrical corporations.	Section 6
(c) (19)	A description of how the WMP is consistent with BVES's disaster and emergency preparedness plan prepared pursuant to Public Utilities Code section 768.6, including plans to restore service and community outreach.	Sections 7
(c) (20)	A statement of how BVES will restore service after a wildfire.	Section 8 Section 9
(c) (21)	Protocols for supporting customers during and after a wildfire, outage reporting, supporting low-income customers, billing adjustments, deposit waivers, extended payment plans, suspension of disconnection and nonpayment fees, repair processing and timing, access to electrical corporation representatives, and emergency communications.	Section 5 Section 8
(c) (22)	Description of the processes and procedures used to monitor and audit the WMP, identify and correct WMP deficiencies, and assess the effectiveness of electrical line and equipment inspections.	Section 1 Section 8 Section 10
(c) (23)	Provide a list of persons responsible for executing the WMP and each members responsibility in the process.	Section 2

4. Overview of WMP

4.1 Primary Goal

Each electrical corporation must state the primary goal of its WMP. At a minimum, the electrical corporation must affirm its compliance with California Public Utilities Code section 8386(a):

> *Each electrical corporation shall construct, maintain, and operate its electrical lines and equipment in a manner that will minimize the risk of catastrophic wildfire posed by those electrical lines and equipment.*

The primary objective of the WMP is to ensure that BVES constructs, maintains, and operates its electric lines and equipment in a manner that minimizes the risk of catastrophic wildfire posed by, and to, its lines and equipment. Additionally, the WMP seeks to ensure BVES is compliant with all applicable regulations and statutes. Finally, the WMP intends to assist BVES in its goal to continue to provide customers with safe delivery of service at competitive rates and maintain its role as a valued partner in the community it serves by promoting public safety.

BVES's WMP aims to reduce threats of utility-caused wildfires by eliminating sources of ignition, and to increase resilience of BVES's assets and provide emergency response, in the event of a wildfire affecting the BVES service area, and restoration actions regardless of cause. Another objective of BVES's WMP is to minimize the need to activate PSPS events. Through its WMP, BVES seeks to fulfill the requirements detailed in PUC Section 8386 and associated statutes by identifying wildfire risks and risk drivers within the BVES service territory; providing an overview of strategies, protocols, plans, and programs to mitigate wildfires; tracking metrics to monitor performance of the WMP's initiatives; ensuring the performance of quality control and assurances of completed work; and setting forth protocols for communicating with customers and public-safety partners throughout wildfire mitigation, PSPS, and emergency events.

BVES identifies its objectives as categorized by timeframe: objectives to accomplish before the next annual WMP update, within the next three years, and within the next ten years.

4.2 Plan Objectives

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

Over the course of 2023, the primary objective of BVES is to continue to reduce wildfire risks through the execution of its grid hardening initiatives, risk assessment and prioritization, and improve the leveraging of enhanced situational awareness and weather monitoring capabilities. For grid hardening, BVES will continue to replace bare wire with covered wire in the highest risk areas and harden every main evacuation route as its highest objectives. Regarding situational awareness, goals include continued improvement through BVES's contracted meteorologist, Technosylva near-real-time fire risk assessment applications and weather stations, improving coordination and communication with stakeholders, employing forecasting capabilities through fire predictive live models, and continuing aggressive vegetation management and inspection. BVES also plans to continue to enhance its data collection and handling. BVES will continue to improve its workforce readiness through recruitment, training, and the strategic use of consultants to supplement BVES staff.

4.3 Proposed Expenditures

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

Table 4-1 provides an example of the minimum acceptable level of information summarizing an electrical corporation's WMP expenditures. The financials represented in the summary table equal the aggregate spending listed in the financial tables of the QDR (see the Energy Safety Data Guidelines). Energy Safety's WMP evaluation, including approval or denial, must not be construed as approval of, or agreement with, costs listed in the WMP.

BVES's projected expenditures in thousands of U.S. dollars per year for the next three-year WMP cycle, as well as the planned and actual expenditures from the previous three-year WMP cycle (2020-2022) is provided in Table 4-1, below. The financials represented in the table equal the aggregate spending listed in the financial tables of the QDR.

Table 4-1 Summary of WMP Expenditures

Year	Spend (Thousands $USD)
2020	Planned = $11,417 Actual = $9,154 ± △ = ($2,262)
2021	Planned = $15,218 Actual = $12,088 ± △ = ($3,130)
2022	Planned = $16,109 Actual = $15,232 ± △ = ($877)
2023	Planned = $17,673
2024	Planned = $35,081
2025	Planned = $8,948

4.4 Risk Informed Framework

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

- *To develop a WMP that achieves an optimal level of life safety, property protection, and environmental protection, while also being in balance with other performance objectives (e.g., reliability and affordability)*
- *To integrate risk modeling outcomes with a range of other performance objectives, methods, and subject matter expertise to inform decision-making processes and the spatiotemporal prioritization of mitigations*
- *To target mitigation efforts that prioritize the highest-risk equipment, wildfire environmental settings, and assets-at-risk (e.g., people, communities, critical infrastructure), while still satisfying other performance objectives defined by the California Public Utilities Commission (CPUC) (e.g., reliability and affordability)*

- *To provide a decision-making process that is clear and transparent to internal and external stakeholders, including clear evaluation criteria and visual aids (such as flow charts or decision trees)*

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

The risk-informed approach adopted by BVES incorporates several components displayed in Table 4-2, below. The evaluation and management of risk takes into consideration a range of performance objectives such as reliability, environmental protection, resiliency, property protection, and life safety. Additionally, BVES integrates cross-disciplinary expertise into its evaluation and management of risk process. Lastly, BVES engages various stakeholder groups as part of the decision-making process.

Table 4-2 Exemplar Risk-Informed Approach Components

Risk-Informed Approach Component	Brief Description
1. Goals and Objectives	The first step in the risk-informed approach is to identify the primary goal and objectives of BVES WMP. The overall risk reduction objectives of the WMP are specific to BVES and are defined in Section 4.2.
2. Scope of Application (i.e., electrical corporation service territory)	Next, BVES defines the physical characteristics of the system in terms of its major elements: utility service area characteristics, electrical infrastructure, wildfire environmental settings, and various assets-at-risk (e.g., communities and people, property, critical infrastructure, cultural/historical resources, environmental services). Knowledge and understanding of how individual system elements interface are essential to this step. Sections 5–5.4 provide details on what BVES presents regarding physical traits, environmental characteristics, and potential assets at risk in their service territory.
3. Hazard Identification	The third step is to identify hazards and determine their likelihoods. Section 6.2.1 provides an overview of BVES hazard identification.
4. Risk Scenario Identification	The fourth step, based on the context and desired values, is for BVES to develop risk scenarios that could lead to an undesirable event. Risk scenario techniques that may be employed include event tree analysis, fault tree analysis, preliminary hazard analysis,

	and failure modes and effects analysis. Section 6.3 provides instructions on risk scenario identification.
5. Risk Analysis (i.e., likelihood and consequences)	The fifth step is to evaluate the likelihood and consequences of the identified risk scenarios to understand the potential impact on the desired goals and objectives. The consequences are based on risk components fundamental to wildfire risk and PSPS event risk, given BVES's scope of application and portfolio of wildfire mitigation initiatives. Section 6.2.2 provides instructions on the risk analysis.
6. Risk Presentation	The sixth step is to consider how the risk analysis is presented to the stakeholders. Section 6.4 provides details on risk presentation.
7. Risk Evaluation	After the risk analysis is complete, hazards can be resolved by either assuming the risk associated with the hazards or eliminating or controlling the hazards. Risk evaluation includes identification of criteria, processes, and procedures for identifying critical risk - both spatially and temporally. Risk evaluation must also include, as a minimum, evaluating the seriousness, manageability, urgency, and growth potential of the wildfire hazard/risk. Risk evaluation should be used to determine whether the individual hazard/risk should be mitigated. Risk evaluation and risk-informed decision-making should be done using a consensus approach involving a range of key stakeholder groups. Section 7 provides details for BVES risk evaluation process and risk-informed decision making.
8. Risk Mitigation and Management	In the final step, BVES identifies which risk management strategies are appropriate given practical constraints such as limited resources, costs, and time. BVES indicates the high-level risk management approach, such as preventing the risk or mitigating the risk (i.e., reducing its likelihood and consequences) as determined in Step 7. BVES identifies risk mitigation initiatives (or a portfolio of initiatives) and prioritize their implementation based on both spatial and temporal considerations. This step includes determining which risk mitigation strategies

	are appropriate and most effectively meet the intent of the WMP goals and objectives, while still in balance with other performance objectives. It also includes the processes, procedures, and monitoring strategies to develop, review, and execute schedules for implementation of mitigation initiatives and activities (as well as interim strategies). Section 8 provides instructions for reporting on initiatives to mitigate identified risks.

5. Overview of the Service Territory

In this section of the WMP, the electrical corporation must provide a high-level overview of its service territory and key characteristics of its electrical infrastructure. This information is intended to provide the reader with an understanding of the physical and technical scope of the electrical corporation's WMP. Sections 5.1 - 5.4 below provide detailed instructions.

5.1 Service Territory

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

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

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

The Figure 5-1 and Table 5-1 provide a high-level description of BVES's service territory.

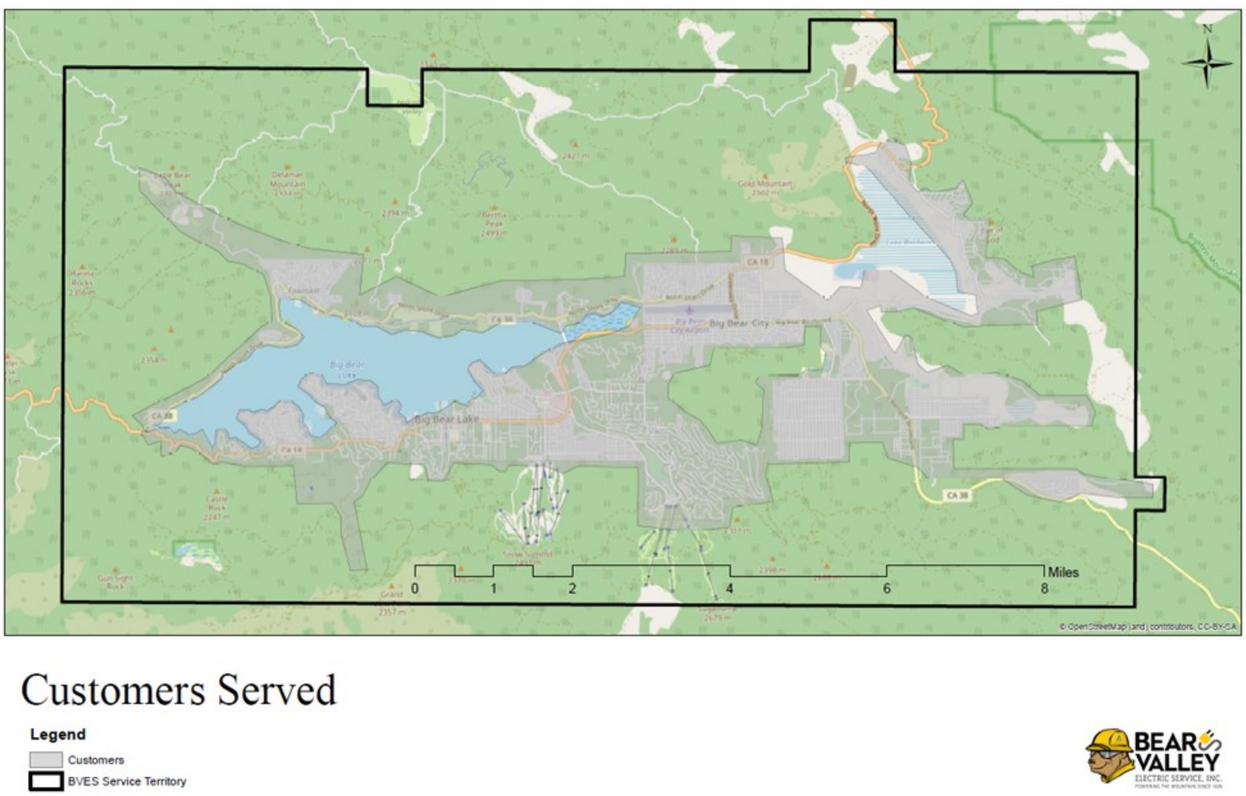


Figure 5-1 Service Territory and Customers Served

Table 5-1 BVES Service Territory Overview

Characteristic	Description
Area Served	32 sq miles

Number of Customers Served	24,691
Number of Counties and Cities Served	1 County (San Bernardino), 1 City (Big Bear Lake)
Total Circuit Miles	267.1
Overhead Circuit Miles	206.7
Underground Circuit Miles	60.4

5.2 Electrical Infrastructure

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

Table 5-2 Overview of Key Electrical Equipment

Type of Equipment	HFTD	Non-HFTD	Total
Substations (#)	13	0	13
Power Generation Facilities (#)	1	0	1
Overhead, Underground & Hardened Transmission Lines (Circuit Miles)	0	0	0
Overhead Distribution Lines (Circuit Miles)	206.7	0	206.7
Hardened Overhead Distribution Lines (Circuit Miles)	31.45	0	31.45
Underground Distribution Lines (Circuit Miles)	60.4	0	60.4
Distribution Transformers (#)	2902	0	2902
Reclosers (#)	15	0	15
Poles (#)	9,156	0	9,156
Towers (#)	0	0	0

Microgrids (#)	0	0	0

5.3 Environmental Settings

The electrical corporation must provide a high-level overview of the wildfire environmental settings within its service territory.

5.3.1 Fire Ecology

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

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

BVES's territory comprises the higher elevation and cooler parts of the San Bernardino mountains. Topographically the area generally consists of north/south facing slopes. Elevation ranges from as low as 4,000 to 10,200 feet. The major ridges generally run east to west, specifically the Sugarloaf Mountain and Holcomb Valley ranges. The mean annual precipitation is about 30 to 40 inches, with the majority in the form of snow in the winter months. Mean annual temperature is about 40 to 50 degrees Fahrenheit. The mean freeze-free period is about 150 to 200 days. Due to Bear Valley's small size its service territory does not consist of multiple ecological regions.

The predominant natural plant community is Jeffery/Ponderosa pine series. There are small areas of coulter pine series, mixed chaparral shrub lands transitioning to the east where there are juniper/pinion woodlands. Some fir and lodgepole pine series are common in the north facing higher elevations. Future breakdown of the vegetation found in the area:

Grasslands: Alpine habitat, beaked sedge, bur-reed, creeping ryegrass, shorthair sedge, sedge, and tufted hair grass series.

Shrub lands: Big sagebrush, black sagebrush, bush chinquapin, deer brush, eastwood manzanita, green leaf manzanita, interior live oak - chaparral whitethorn, interior live oak - canyon live oak shrub, interior live oak - scrub oak shrub, mixed saltbush, mixed scrub oak, mountain whitethorn, rothrock sagebrush, rubber rabbit brush, scrub oak, and scrub oak - chamise series.

Forests and woodlands: Aspen, black cottonwood, black oak, coulter pine - canyon live oak, curlleaf mountain-mahogany, incense-cedar, jeffrey pine, ponderosa pine, limber pine, lodgepole pine, mixed conifer, mixed subalpine forest, mountain juniper, singleleaf pinion, and white fir series.

A large portion of the Big Bear Valley Wildland Urban Interface has not burned in well over 105 years and has missed approximately four fire intervals in the conifer or mixed conifer vegetation structure. According to the California Department of Forestry (FRAP) data derived from the United States Forest Service material, 42% of the Big Bear Valley Wildland Urban Interface is a

Fire Regime I; 47% is a Fire Regime III; and 3% is in Fire Regime IV. Even without the drought and tree mortality issues, this is considered high fire hazard conditions with old decadent brush, heavy fuel loadings, and over-densification of trees that have not been comprehensively treated for a number of years.

Table 5-3 Vegetation Types in the Service Territory

Vegetation Type	Acres	Percentage of Service Territory
Short, Sparse Dry Climate Grass	241.7455868	0.41
Low Load, Dry Climate Grass	391.5194723	0.67
Low Load, Dry Climate Grass-Shrub	322.3434777	0.55
Moderate Load, Dry Climate Grass-Shrub	14226.21045	24.18
Low Load Dry Climate Shrub	56.61822526	0.10
Moderate Load Dry Climate Shrub	0.142417401	0.00
Low Load, Humid Climate Timber-Shrub	3493.005658	5.94
High Load, Dry Climate Shrub	460.7446809	0.78
Very High Load, Dry Climate Shrub	4333.899448	7.37
Low Load Dry Climate Timber-Grass-Shrub	151.4796424	0.26
Moderate Load, Humid Climate Timber-Grass-Shrub	6648.109504	11.30
Timber Understory Dynamic ML (TSYL 2022)	8928.199803	15.18
Low Load Compact Conifer Litter	3.069616227	0.01
Low Load Broadleaf Litter	26.38574582	0.04
Timber Litter ML (TSYL 2022)	11072.32054	18.82

5.3.2 Catastrophic Wildfire History

The electrical corporation must provide a brief narrative summarizing its wildfire history for the past 20 years (2002-2022) as recorded by the electrical corporation, CAL FIRE, or another authoritative sources. For this section, wildfire history must be limited to electrical corporation ignited catastrophic fires (i.e., fires that caused at least one death, damaged over 500 structures, or burned over 5,000 acres). This includes catastrophic wildfire ignitions reported to the CPUC that may be attributable to facilities or equipment owned by the electrical corporation and where the cause of the ignition is still under investigation. Electrical corporations must clearly denote those ignitions as still under investigation. In addition, the electrical corporation must provide catastrophic wildfire statistics in tabular form, including the following key metrics:

- *Ignition date*
- *Fire name*
- *Official cause (if known)*
- *Size (acres)*
- *Number of fatalities*
- *Number of structures damaged*

- *Estimated financial loss (U.S. dollars)*

Table 5 4 provides an example of the content and level of detail required for the tabulated historical catastrophic utility-related wildfire statistics. The electrical corporation must provide an authoritative government source (e.g., CPUC, CAL FIRE, U.S. Forest Service, or local fire authority) for its reporting of wildfire history data and loss/damage estimates, to the extent this information is available.

BVES has not experienced an electrical corporation ignited catastrophic fire, so this section is not applicable to BVES.

Table 5-4 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$)
N/A	N/A	N/A	N/A	N/A	N/A	N/A

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

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

BVES has not experienced an electrical corporation ignited catastrophic fire, so this section is not applicable to BVES.

5.3.3 High Fire Threat Districts

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

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

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

BVES’s entire service territory falls within the HFTD designation. The territory primarily contains HFTD Tier 2 with a small portion of Tier 3. The only asset that falls within the Tier 3 designation is the Radford Line, which is a sub-transmission line that supplies electric power from Southern California Edison’s (SCE) system and operates at 34.5 kV and serves at a maximum capacity of 5 MWs. The following figure and table provide further detail to the breakdown of HFTD in Bear Valley’s service territory.

Figure 5-2 HFTD Tier Breakdown for the Service Territory

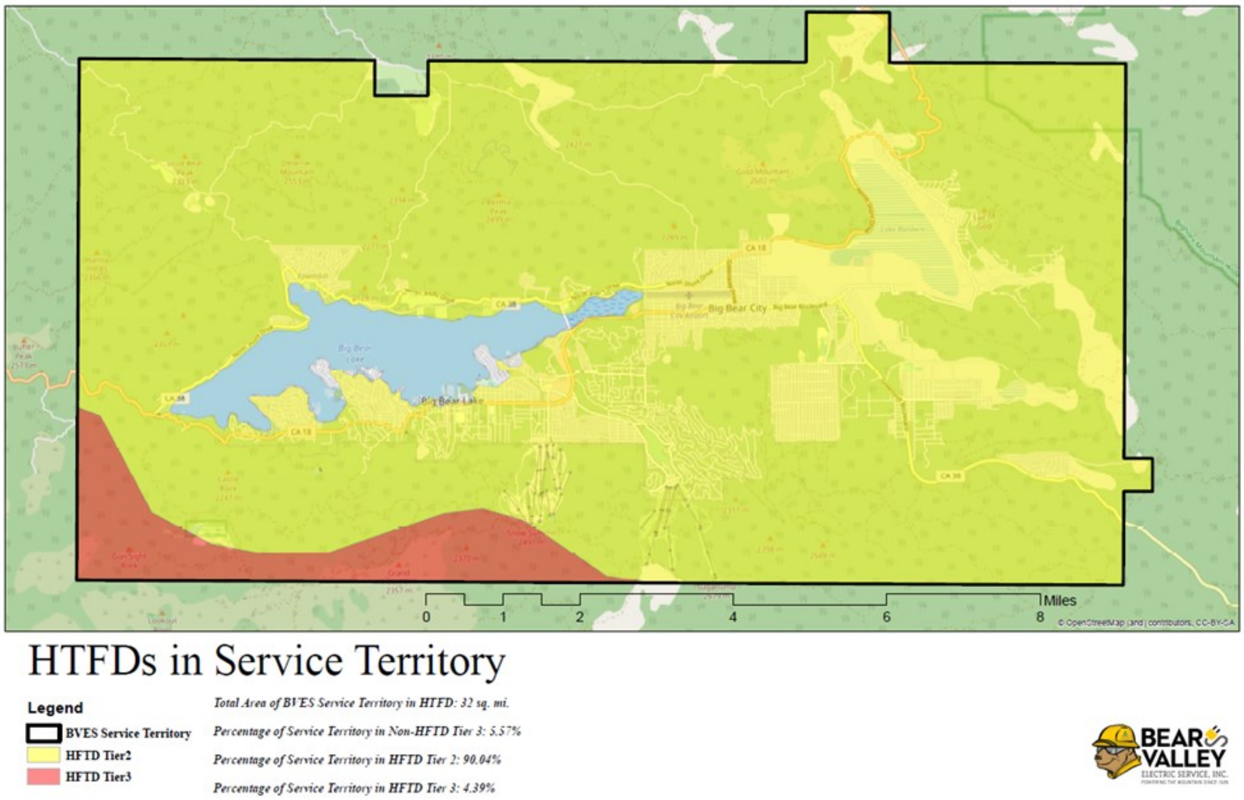


Table 5-5 Example of an Electrical Corporation's HFTD Statistics

High Fire Threat District	Total Area of Individual District (sq. mi.)	% of Total Service Territory
Non-HFTD[1]	1.7824	5.57%
Tier 2	28.8128	90.04%
Tier 3	1.4048	4.39%
Total	32	100%

5.3.4 Climate Change

It is critical for the electrical corporation to understand general climate conditions and how climate change impacts the frequency and the intensity of extreme weather events and the vegetation that fuels fires.

5.3.4.1 General Climate Conditions

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

[1] The Non-HFTD portion of BVES's service territory is Big Bear Lake where no assets exist.

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

The electrical corporation must also provide a graph of the average precipitation and maximum and minimum temperatures for each distinct climatic region of its service territory. At a minimum, it must provide one graph in the main body of the report.

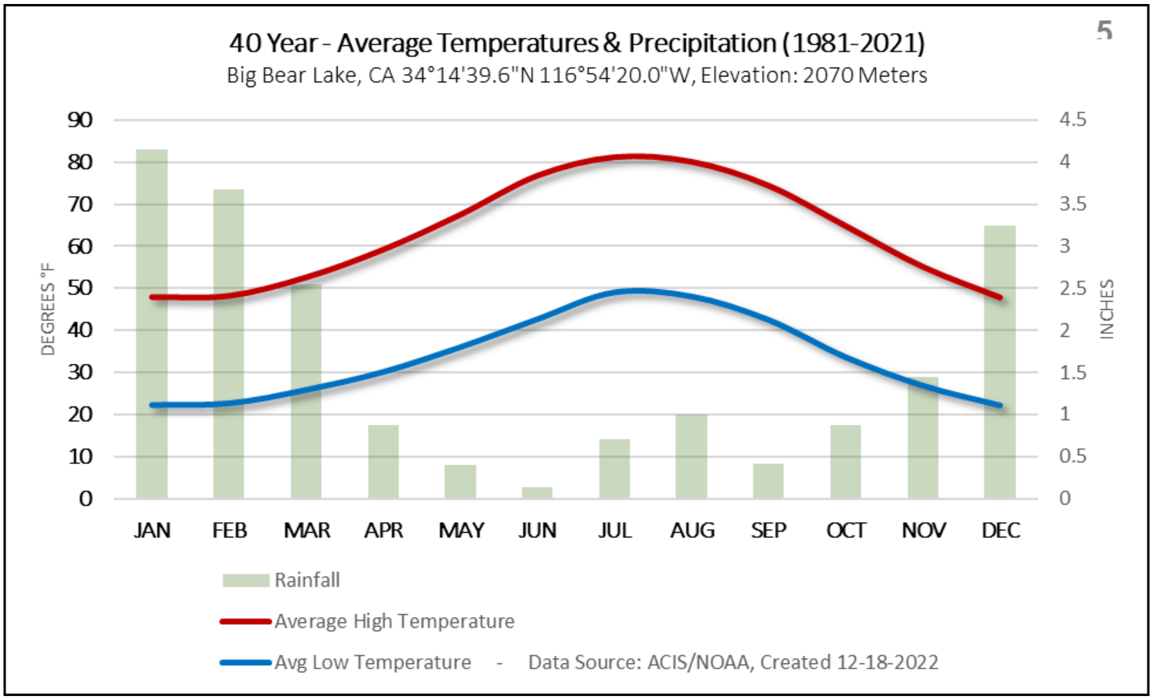


Figure 5-3 Annual Mean Climatology for the Electrical Corporation's Service Territory

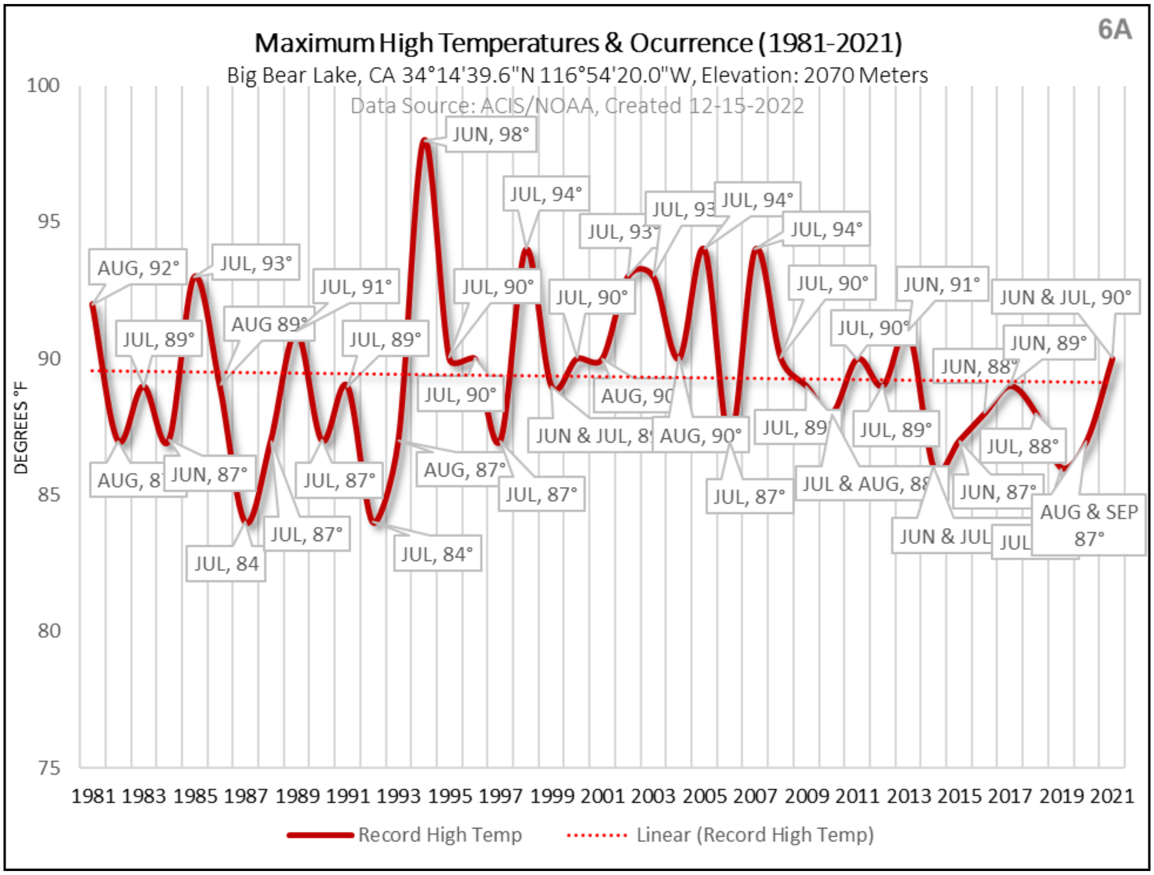


Figure 5-4 Annual Maximum Temperature and Occurrence for the Electrical Corporation's Service Territory

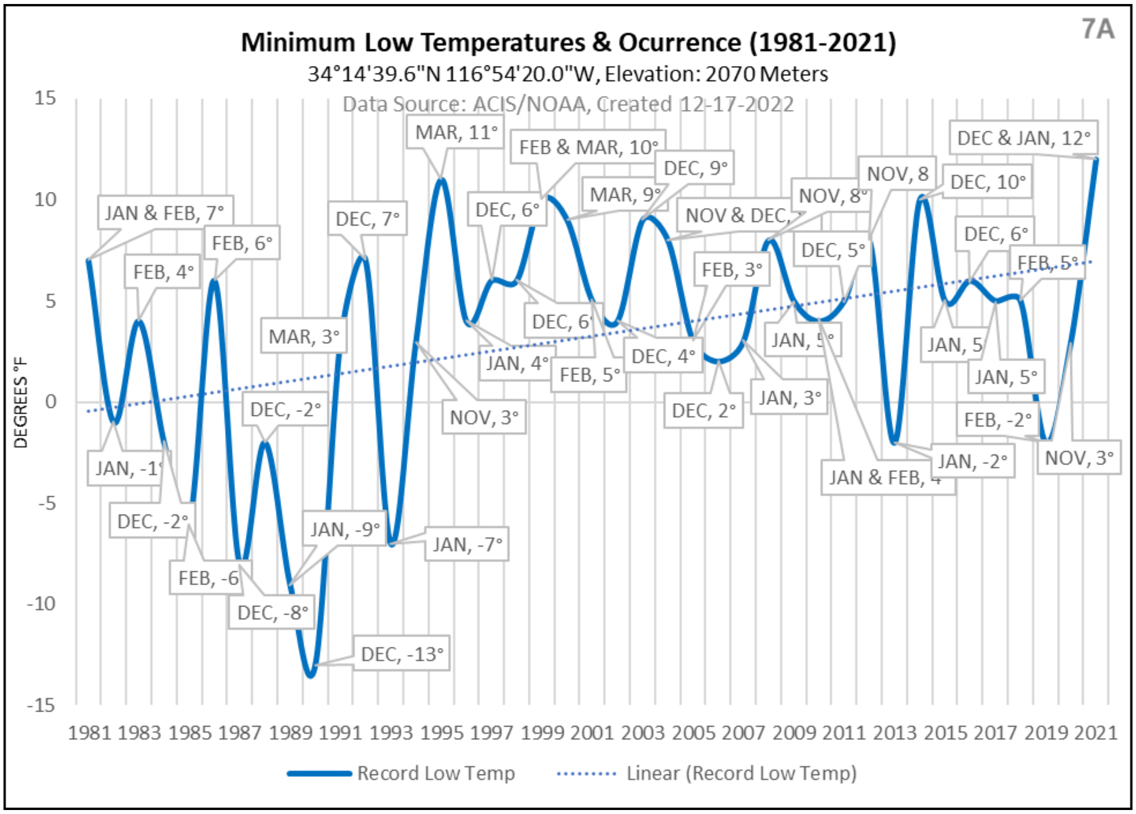


Figure 5-5 Annual Minimum Temperature and Occurrence for the Electrical Corporation's Service Territory

5.3.4.2 Climate Change Phenomena and Trends

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

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

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

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

Historical data over the past 60 years for the Big Bear area has shown a steady increase in mean temperature with a gradual decline in natural snowfall, while rainfall remains near average. If the current pattern continues, we can expect a continued increase in temperature by some 2-3 degrees through the year 2100. This could have severe long-term implications, leading to drier winters with more extreme weather events; storms would tend to impact the region less frequently but more violently. This would result in lower lakes, reservoirs & aquafers, which would promote lower fuel moisture supporting more catastrophic wildfires. Short-term pattern changes in the ENSO (El Niño and the Southern Oscillation) may bring temporary relief for the drought-stricken west, but are expected to remain just that, temporary. Scientists cannot say with certainty if we will break this pattern cycle and combat the effects of global warming, but if history is any indication, drier winters, gradually warming temperatures, and more extreme meteorological events appear to be the long-term trend.

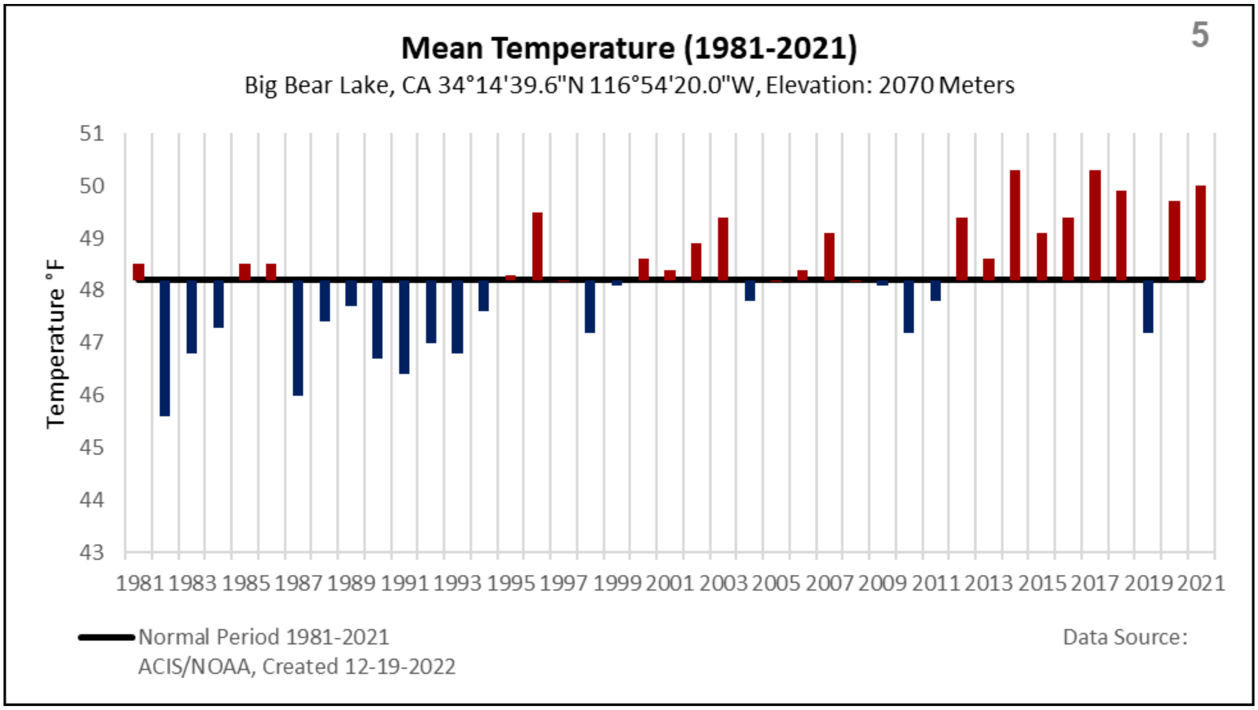


Figure 5-6 Mean Annual Temperature for Service Territory, 1900s–2020s

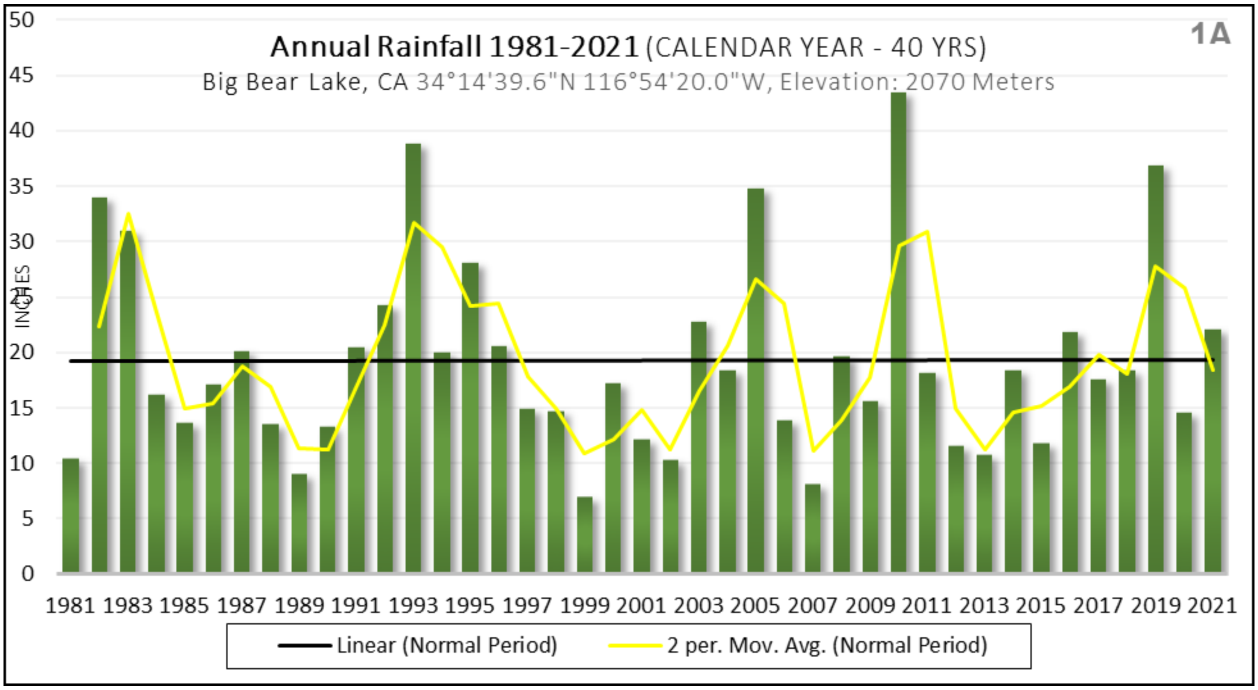


Figure 5-7 Mean Annual Precipitation for Service Territory, 1900s–2020s

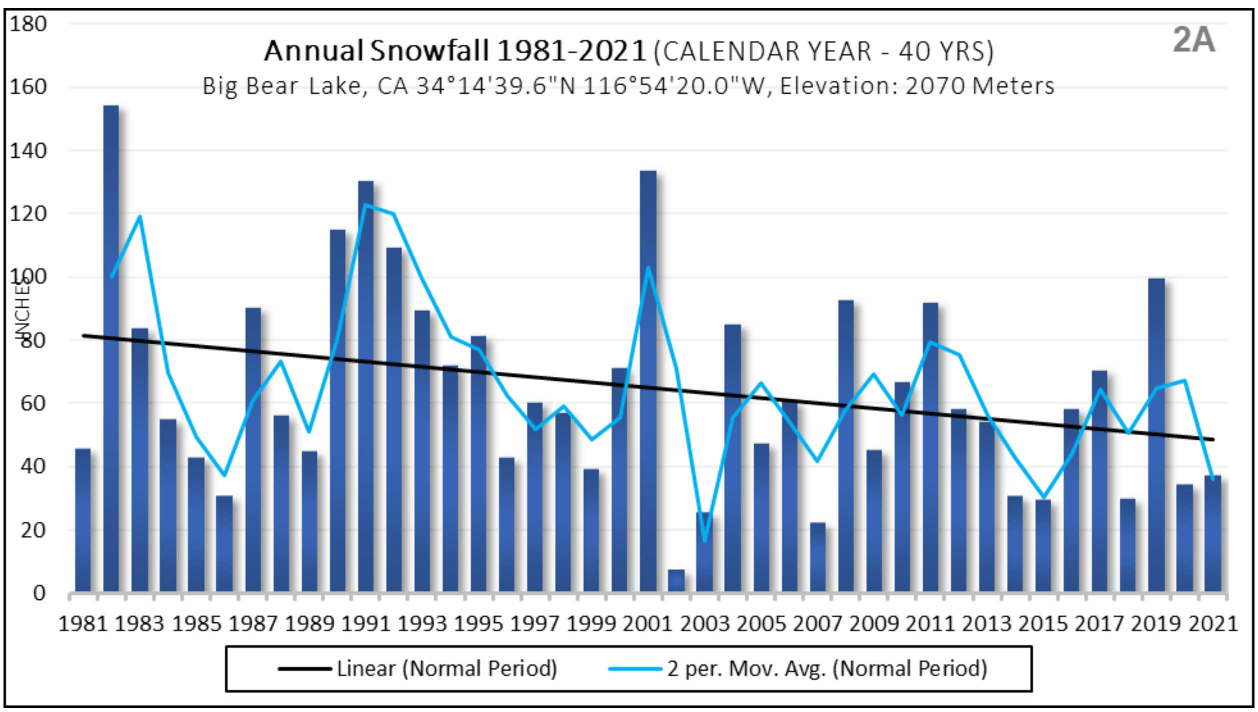


Figure 5-8 Mean Annual Precipitation for Service Territory, 1900s–2020s

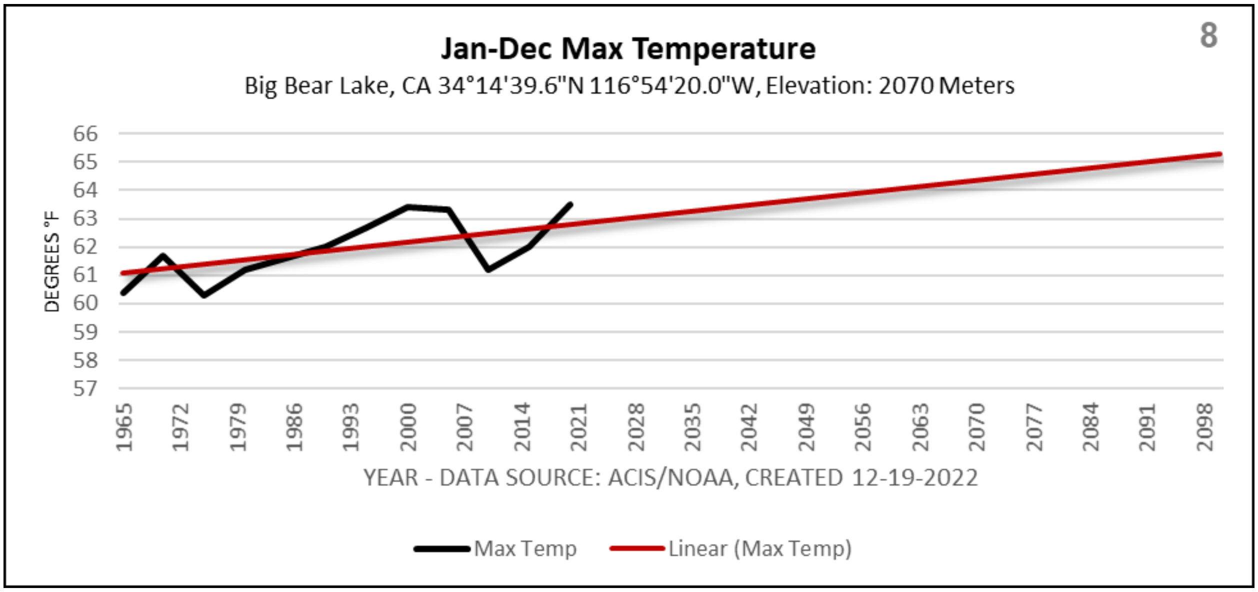


Figure 5-9 Projected Change in Maximum Temperature (Daytime Highs) Through 2100 for the Service Territory

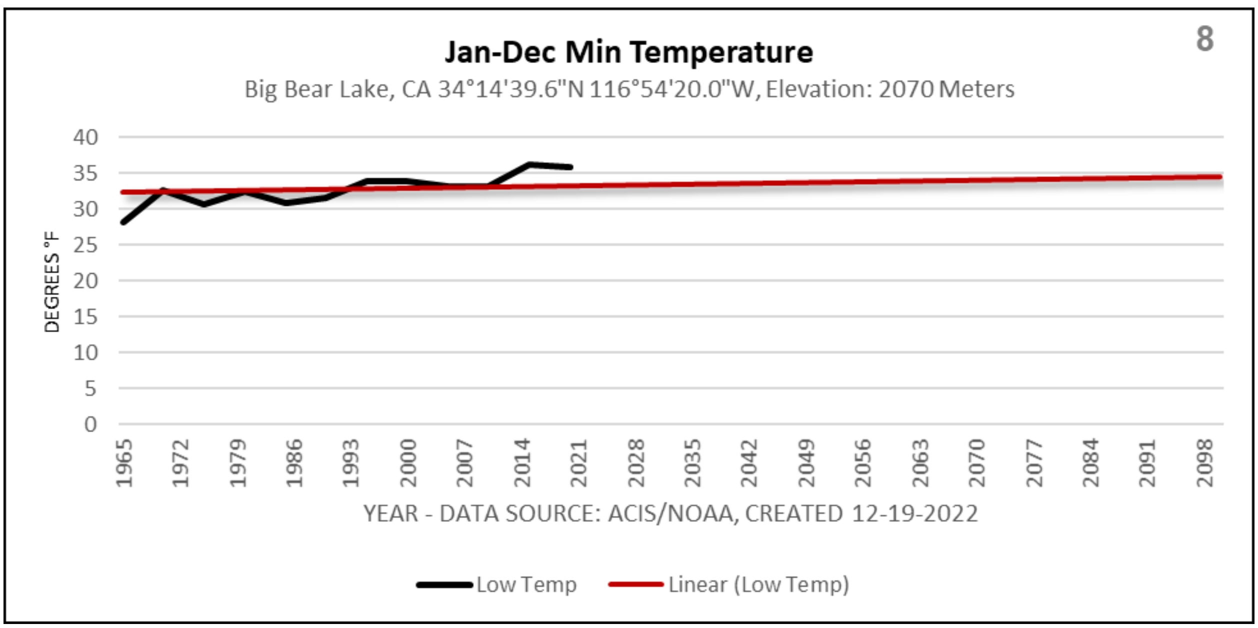


Figure 5-10 Projected Change in Minimum Temperature (Nighttime Lows) Through 2100 for the Service Territory

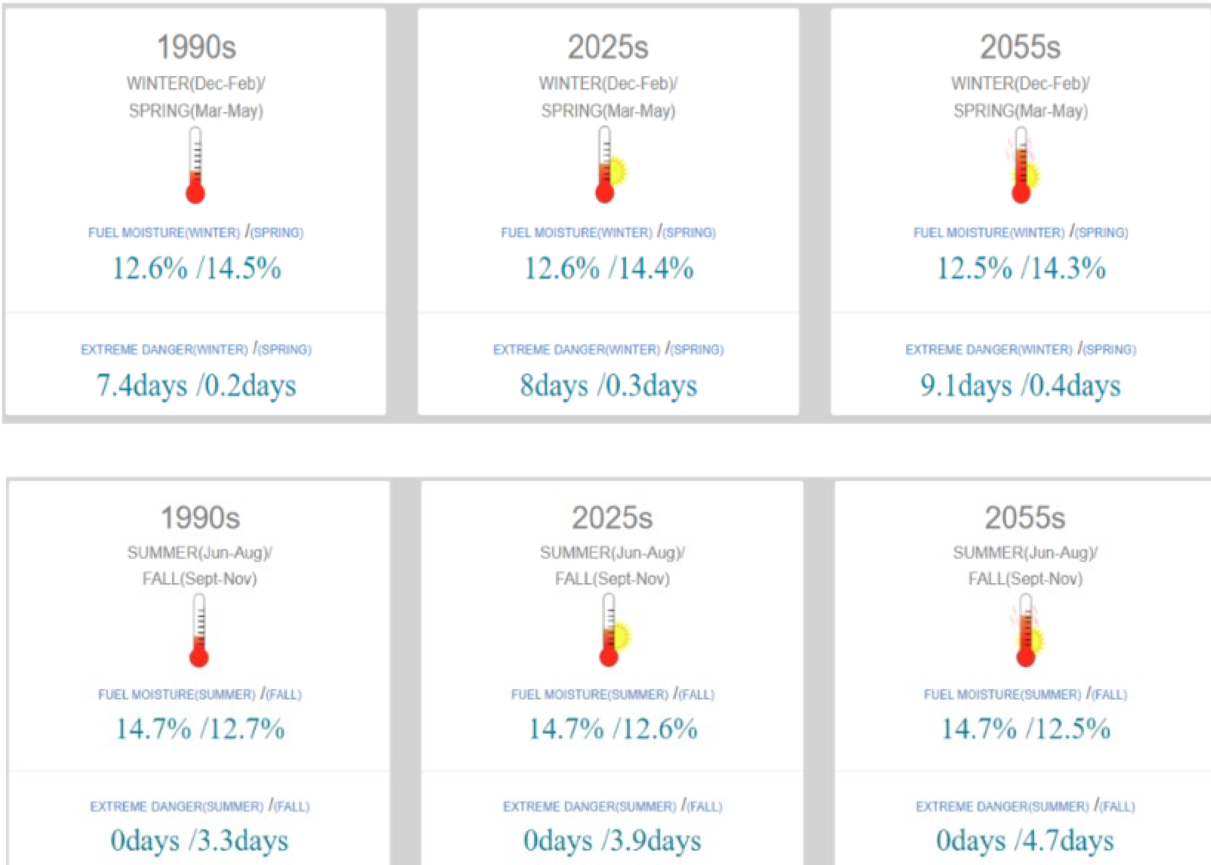


Figure 5-11. Projected Changes in Average Fuel Moisture and Average Number of Days of Extreme Fire Danger for Winter/Spring and Summer/Fall Periods for the Service Territory Based on Global Climate Model Outputs

5.3.5 Topography

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

Topographically, the 270 square mile area generally consists of north/south facing slopes. Elevations range from as low as 4,000 feet to 10,200 feet. The major ridges generally run east to west, specifically the Sugarloaf Mountain and Holcomb Valley ranges.

5.4 Community Values at Risk

In this section of the WMP, the electrical corporation must identify the community values at risk across its service territory. Sections 5.4.1–5.4.5 provide detailed instructions.

5.4.1 Urban, Rural, and Highly Rural Customers

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

BVES services 24,691 customers. Those customers are primarily urban customers with 21,109 customers primarily concentrated in the City of Big Bear Lake and the unincorporated communities of Big Bear City, Sugarloaf and Erwin Lake. BVES also services a small portion of urban customers with 3,531 customers primarily concentrated in the unincorporated communities of Baldwin Lake, Fawnskin and Lake Williams. BVES does not service any highly rural customers.

5.4.2 Wildland-Urban Interfaces

The electrical corporation must provide a brief narrative describing the wildland-urban interfaces (WUIs) across its service territory. Refer to Appendix A for definitions.

BVES's service territory falls entirely in the wildland-urban interface (WUI) designation.

5.4.3 Communities at Risk from Wildfire

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

5.4.3.1 Individuals at Risk from Wildfire

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

BVES's entire service territory falls within the HFTD designation. The territory primarily contains HFTD Tier 2 with a small portion of Tier 3. Due to this make-up, all 24,691 customer are considered at-risk from wildfires. As BVES completes its grid hardening initiatives some of these customers will be at a reduced risk because of said efforts but with an HFTD designation their risk will never be fully eliminated.

5.4.3.2 Social Vulnerability and Exposure to Electrical Corporation Wildfire Risk

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

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

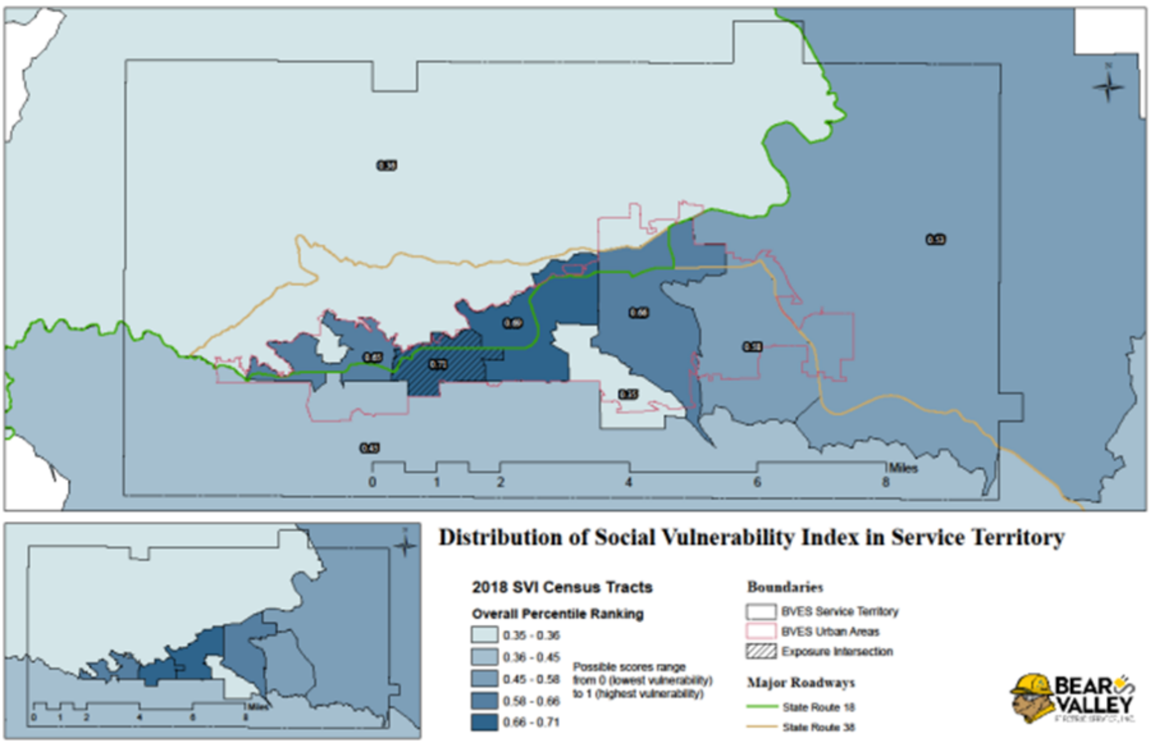
In addition, the electrical corporation must provide a single geospatial map showing its service territory (polygon) overlaid with the distribution of the SVI and exposure intersection and urban and major roadways. Any additional maps needed to provide clarity and detail should be included in Appendix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

The BVES territory contains one Census tract "112.05, San Bernardino County, California" which is defined as the intersection of vulnerability and community exposure. This census track exceeds the 70th percentile according to the Social Vulnerability Index and exceeds the 85th percentile in BVES wildfire consequence risk.

The high wildfire consequence risk is attributed to the Radford circuit. BVES is planning to upgrade the Radford circuit in 2023 with covered conductor which will significantly reduce the wildfire consequence risk for Census tract “112.05, San Bernardino County, California”. Upon completion of the Radford upgrade, BVES will reevaluate the wildfire consequence risk for each of the circuits and upgrade the Social Vulnerability and Exposure to Electrical Corporation Wildfire Risk Map.

Census tract “112.05, San Bernardino County, California” contains part or all of the following circuits: Shay Circuit, Lagonita Circuit, Harnish Circuit, Georgia Circuit, Garstin Circuit, Eagle Circuit and Boulder Circuit.

Figure 5-12 SVI Overlay of Service Territory



5.4.3.3 Sub-Divisions with Limited Egress or No Secondary Egress

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

BVES’s service territory does not contain sub-divisions with limited egress or no secondary egress. This was verified using CAL FIRE and their OSFM Subdivision Review Program map.

5.4.4 Critical Facilities and Infrastructure at Risk from Wildfire

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

BVES's service territory falls entirely in HFTD Tier 2 and Tier 3, meaning that all critical facilities and infrastructure are located in HFTD. No critical facilities and infrastructure reside outside of HFTD.

5.4.5 Environmental Compliance and Permitting

In this section, the electrical corporation must provide a summary of how it ensures its compliance with applicable environmental laws, regulations, and permitting related to the implementation of its WMP. This overview must include:

- *A description of the procedures/processes to ensure compliance with relevant environmental laws, regulations, and permitting requirements before and during WMP implementation. The process or procedure should include when consultation with permittees occurs (i.e., at what stage of planning and/or implementation of activities described in the WMP)*
- *Roadblocks the electrical corporation has encountered related to environmental laws, regulations, and permitting related to implementation of its WMP and how the electrical corporation has addressed, is addressing, or plans to address the roadblocks.*
- *Any notable changes to its environmental compliance and permitting procedures and processes since the last WMP submission and a brief explanation as to why those changes were made. Include any planned improvements or updates to the initiative and the timeline for implementation.*

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

BVES contacts an environmental consultant to ensure that our main facility and substations are properly permitted. The consultant informs BVES of permitting requirements and issues. Permits include but are not limited to Air Quality, Water Quality and Discharge, Hazardous Materials Business Plan, and Spill Prevention Control and Countermeasures Plan.

BVES adheres to and complies with all applicable environmental laws and regulations including but not limited to the Endangered Species Act, Storm Water Pollution Prevention Plan (SWPPP), California Environmental Quality Act (CEQA), and consults with the State Historic Preservation Officer (SHPO). BVES frequently follows up with agencies to ensure all permit submittal requirements are met. There have been no major changes, adjustments, or roadblocks to the environmental process since the last WMP.

Table 5-6 Relevant State and Federal Environmental Laws, Regulations, and Permitting Requirements for Implementing the WMP

Environmental Law, Regulation, or Permit	Responsible Permittee/Agency
Endangered Species Act Section 10(a)(1)(B) Incidental Take Permit	United States Fish and Wildlife Service
CEQA – BVES is seeking a categorical exclusion for the covered conductor project along the Radford sub-transmission (34.5kV) line	USFS
Storm Water Pollution Prevention Plan (SWPPP)	US EPA
National Environmental Policy Act (NEPA)	US EPA
Highway Encroachment Permit	CalTrans

6. Risk Methodology and Assessment

In this section of the WMP, the electrical corporation must provide an overview of its risk methodology, key input data and assumptions, risk analysis, and risk presentation (i.e., the results of its assessment). This information is intended to provide the reader with a technical understanding of the foundation for the electrical corporation's wildfire mitigation strategy for its Base WMP. Sections 6.1–6.7 below provide detailed instructions.

For the 2023-2025 Base WMP, the electrical corporation does not need to have performed each calculation and analysis indicated in sections 6.2, 6.3, and 6.6. If the electrical corporation is not performing a certain calculation or analysis, it must describe why it does not perform the calculation or analysis, its current alternative to the calculation or analysis (if applicable), and any plans to incorporate those calculations or analyses into its risk methodology and assessment.

BVES has significantly advanced its risk methodologies and assessments, including by hiring the risk modeling firm Technosylva to improve Bear Valley's risk assessment, modeling, and monitoring capabilities. However, BVES is not currently performing all the suggested risk assessment activities suggested by Energy Safety. Over the past two years, BVES has sought external help with risk mapping and modeling from REAX Engineering and Technosylva. Additionally, and as described in Section 7 of this WMP, BVES has improved its Fire Safety Circuit Matrix, Risk-Based Decision-Making Model, and RSE analysis.

BVES is a small, geographically compact utility with limited budgets and staff. The service territory is designated as Tier 2 and Tier 3 HFTD and is vulnerable to utility ignitions and wildfire. 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 will adopt and implement appropriate risk methodologies, assessments, and modeling as appropriate, where such approaches and tools will allow BVES to gain a better understanding of the risks and how it should mitigate those risks.

6.1 Methodology

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

6.1.1 Overview

The electrical corporation must provide a brief narrative describing its methodology for quantifying its overall risk of wildfires and PSPS. This methodology will help inform the development of its wildfire mitigation strategy (see Section 7). The electrical corporation must describe the methodology and underlying intent of this risk assessment in no more than five pages, inclusive of all narratives, bullet point lists, and any graphics.

The following is an exemplar of this overview:

The risk assessment in this WMP is based on a quantified risk approach using a range of industry-recognized standards, best practices, and research to determine the electrical corporation's overall risk of wildfires and PSPS for its service territory. The intent of performing this risk analysis is to:

- *Understand the overall risk and associated risk components of wildfires and PSPS events spatially and temporally across the electrical corporation's service territory*
- *Use this understanding of risk to inform the development of a comprehensive wildfire mitigation strategy in Section 7 that achieves the goals and objectives stated in Section 4.1 and 4.2*

The risk analysis is shown schematically in Figure 6-1 below. The approach consists of the following:

- *Identifying key wildfire and PSPS hazards and risk components across the electrical corporation's service territory (refer to Section 6.2.1).*
- *Identifying key modeling tools, inputs, and assumptions to quantify the likelihood and consequence of the electrical corporation's overall risk (refer to Section 6.2.2 and 6.2.3).*
- *Identifying credible scenarios that would expose surrounding people, assets, and natural resources (PAR) to wildfire or PSPS risks (refer to Section 6.3).*
- *Summarizing the overall utility risk and key metrics (refer to Section 6.4).*
- *Presenting the quality assessment and quality control procedures for the electrical corporation's risk assessment (refer to Section 6.4).*
- *Improving the risk analysis approach based on lessons learned during the WMP cycle (refer to Section 6.7)*

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 Enterprise (WFA-E) 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-E Wildfire Risk Reduction Model (WRRM) is used to quantify risk metrics from millions of wildfire simulations using the numerous WRF weather scenarios defined. Other key input datasets such as surface and canopy fuels, and live fuel moisture and dead fuel moisture, is developed daily using Machine Learning (ML) models to calculate the wildfire behavior outputs as part of the risk analysis model.

Second, 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. 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.

Wildfire risk forecasts are derived daily, or sometimes twice daily, with a multi-day outlook that displays expected changes 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.

6.1.2 Summary of Risk Models

In this section, the electrical corporation must summarize the calculation approach for each risk and risk component identified in Section 6.2.1. This documentation is intended to provide a quick summary of the models used. The electrical corporation must provide the following information:

- ***Identification (ID)*** *– Unique shorthand identifier for the risk or risk component.*
- ***Risk component*** *– Unique full identifier for the risk or risk component.*
- ***Design scenario(s)*** *– Reference to design scenarios evaluated with the model to calculate the risk or risk component. These must be defined in Section 6.3.*
- ***Key inputs*** *– List of key inputs used to evaluate the risk or risk component. These can be in summary form (e.g., the electrical corporation may list "equipment properties" rather than listing out equipment age, maintenance history, etc.).*
- ***Sources of inputs*** *– List of sources for each input parameter. These must include data sources (such as LANDFIRE) and modeling results (such as wind predictions) as relevant to the calculation of the risk or risk component. If the inputs come from multiple sources, each source should be on a new line.*
- ***Key outputs*** *– List of outputs calculated for the risk or risk component.*
- ***Units*** *– List of the units associated with the key outputs.*

The electrical corporation must provide additional detail on each model in the appendix, in accordance with the requirements documented in Appendix B.

Table 6-1 Summary of Risk Models

ID	Risk Component	Design Scenario(s)	Key Inputs	Source of Inputs (Data and/or Models)	Key Outputs	Units	Reference
N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

6.2 Risk Analysis Framework

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

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

- ***Equipment / Assets*** *(e.g., type, age, inspection, maintenance procedures, etc.)*
- ***Topography*** *(e.g., elevation, slope, aspect, etc.)*
- ***Weather*** *– at a minimum this must include statistically extreme conditions based on weather history and seasonal weather*

- ***Vegetation** (e.g., type/class/species/fuel model, canopy height/base height/cover, growth rates, moisture content, inspection, clearance procedures, etc.)*
- ***Climate change** (e.g., long-term changes in seasonal weather; statistical extreme weather; impact of change on vegetation species, growth, moisture, etc.) at a minimum, this must include adaptations of historical weather data to current and forecasting future climate*
- ***Social vulnerability** (e.g., AFN, socioeconomic factors, etc.)*
- ***Physical vulnerability** (e.g., people, structures, critical facilities/infrastructure, etc.)*
- ***Coping capacities** (e.g., limited access/egress, etc.)*

The implementation of Technosylva and its modeling software is currently underway. As part of this implementation, BVES will have access to the information required in this section. BVES is currently using its two in-house tools (Fire Safety Circuit Matrix and Risk-Based Decision-Making Model) as it has in the past that already incorporates most of the features listed above. Additionally, Bear Valley previously sought risk mapping and modeling information that incorporates wildfire risk and ignition potential in the current and projected climate conditions of 2050. BVES will continue to develop its current models and add additional capability until the time BVES is fully able to holistically understand the dynamic wildfire risk facing BVES and the best measures to adopt to mitigate such risk.

6.2.1 Risk and Risk Component Identification

In this section, the electrical corporation must provide a brief narrative and one or more simple graphics describing the framework that defines its overall utility risk. At a minimum, the electrical corporation must define its overall risk as the comprehensive risk due to both wildfire and PSPS events across its service territory. This includes several likelihood and consequence risk components that are aggregated based on the framework shown in Figure 6-2 below. The following paragraphs define each risk component.

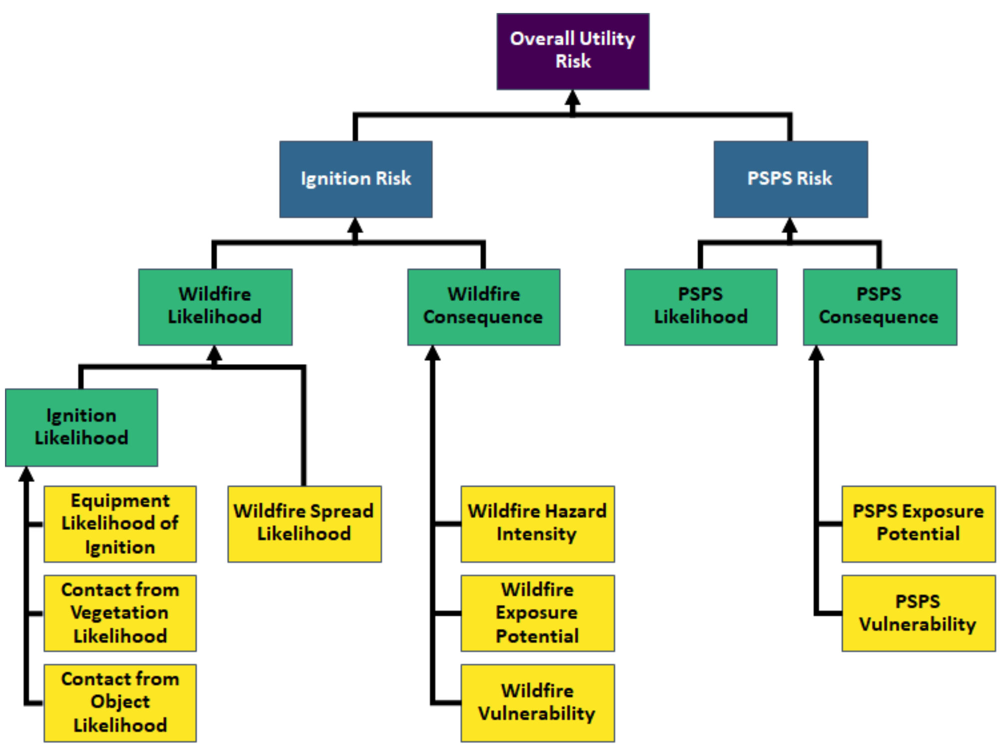


Figure 6-1 Composition of Overall Utility Risk (purple); Utility-related sources of risk including Ignition and PSPS Risks (blue); Intermediate Risk Components (green); and Fundamental Risk Components (yellow)

While the overall risk framework and associated risk components identified in Section 6.2 are the minimum requirements for determining overall risk, the electrical corporation may elect to include additional risk components, as needed, to better define risk for its service territory. Where the electrical corporation identifies additional terms as part of its risk framework, it must define those terms. The electrical corporation must include a schematic demonstrating its adopted risk framework (similar to Figure 6-2), including any components beyond minimum requirements.

As shown in Figure 6-1, overall utility risk is broken down into two individual hazard risks:

- ***Ignition 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*

- ***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*

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 smallest components of risk that the electrical corporation 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 in a electrical corporation's wildfire and PSPS risk calculations.

There are a minimum of five intermediate risk components:

- ***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 to reduce the likelihood of an ignition upon an initiating event.*

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

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

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

There are a minimum of nine fundamental risk components:

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

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

- ***Contact 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.*

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

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

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

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

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

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

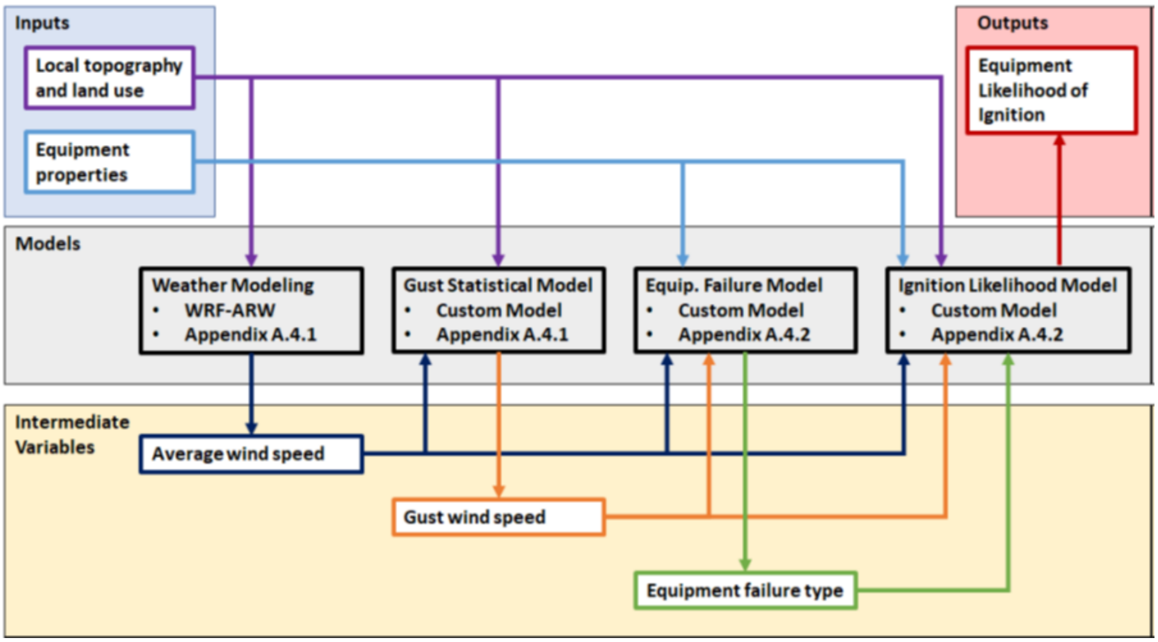
BVES has adopted these definitions for its 2023 WMP and for future risk assessments. The implementation of Technosylva and its modeling software is currently underway. As part of this implementation, BVES will have access to the information required in this section. BVES is currently using its two in-house tools (Fire Safety Circuit Matrix and Risk-Based Decision-Making Model) as it has in the past that already incorporates most of the features listed above. Additionally, Bear Valley previously sought risk mapping and modeling information that incorporates wildfire risk and ignition potential in the current and projected climate conditions of 2050. BVES will continue to develop its current models and add additional capability until the time BVES is fully able to holistically understand the dynamic wildfire risk facing BVES and the best measures to adopt to mitigate such risk.

6.2.2 Risk and Risk Components Calculation

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

The electrical corporation must provide schematics illustrating the calculation of each risk and risk component as necessary to demonstrate the logical flow from input data to outputs, including separate items for any intermediate calculations. An example calculation schematic is provided for the equipment likelihood of ignition in Figure 6-2.

Figure 6-2 Example Calculation Schematic



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

- ***Additional input parameters** beyond the minimum requirements for a specific risk component*
- ***Calculations of additional outputs** beyond the minimum requirements for a specific risk component*
- ***Calculations of additional risk components** defined by the electrical corporation in Section 6.2.1*

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

With the implementation of Technosylva's models, BVES will perform these calculations and expects to have them available in its 2024 WMP Update.

6.2.2.1 Likelihood

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

- *Ignition likelihood*

- *Equipment failure likelihood of ignition*
- *Contact from vegetation likelihood of ignition*
- *Contact from object likelihood of ignition*
- *Burn Probability*
- *PSPS likelihood*

With the implementation of Technosylva's models, BVES will perform these calculations and expects to have them available in its 2024 WMP Update.

6.2.2.2 Consequence

The electrical corporation must calculate the consequences of a fire originating from its equipment and the consequence of implementing a PSPS event to prevent a catastrophic wildfire in the community. The risk components discussed in this section must include at least the following:

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

BVES is working with Technosylva on this capability. With the implementation of Technosylva's models, BVES will perform these calculations and expects to have them available in its 2024 WMP Update. To date, BVES has not met its current threshold to implement a PSPS activation in its territory.

6.2.2.3 Risk

The electrical corporation must calculate each risk and the resulting overall risk defined in Section 6.2.1. The discussion in this section must include at least the following:

- *Ignition risk*
- *PSPS risk*
- *Overall utility risk*

With the implementation of Technosylva's models, BVES will perform these calculations and expects to have them available in its 2024 WMP Update.

6.2.3 Key Assumptions and Limitations

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

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

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

- ***Adaptation of weather history** to current and forecasted climate conditions*
- ***Availability of suppression resources** including type, number of resources, and ease of access to incident location*
- ***Height of wind driving fire spread** / 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*

The electrical corporation must document each assumption in Table 6-2, see the exemplar provided below. The electrical corporation must summarize detailed assumptions made within models in accordance with the model documentation requirements in Appendix B.

Table 6-2 Risk Modeling Assumptions and Limitations as provided by Technosylva

Assumption	***Justification***	***Limitation***	***Applicable Models***
The physical framework development is based on an idealized situation in steady state spread which may not fit some extreme behavior of fires.			WFA-E
Fuels are assumed to be continuous and uniform for the scale of the input (typically between 10 to 30 meter (m) resolution)			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			WFA-E
Fire spread is assumed to be elliptical although there are several variations such as double ellipse, oval, egg-shape, etc.			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.			WFA-E
Reliability of weather inputs in the mid-range forecast (2 to 5 days)			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 (specially 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.			WFA-E
Fire is always assumed to be fully developed. Fire acceleration, flashover, or decay is not considered.			WFA-E
Atmospheric instability which may have a deep impact on ROS (beer 1991) is not considered in the model.			WFA-E
Gusts are not considered in the model			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.			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.			WFA-E
Fuel array description of the vegetation may not perfectly describe fuel characteristics.			WFA-E
Spotting is only considered in surface fires			WFA-E

6.3 Risk Scenarios

In this section of the WMP, the electrical corporation must provide a high-level overview of the scenarios to be used in its risk analysis in Section 6.2. These must include at least the following:

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

The risk scenarios described in Sections 6.3.1 and 6.3.2 below are the minimum scenarios the electrical corporation must assess in its wildfire and PSPS risk analysis. The electrical corporation must also describe and justify any additional scenarios it evaluates.

Each scenario must consider:

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

The implementation of Technosylva and its modeling software is currently underway. As part of this implementation, BVES will have access to the information required in this section. BVES is currently using its two in-house tools (Fire Safety Circuit Matrix, and Risk-Based Decision-Making Model) as it has in the past. BVES will continue to develop its current models and add additional capability until the time BVES is fully able to holistically understand the dynamic wildfire risk facing BVES and satisfy Energy Safety's modeling requirements.

6.3.1 Design Basis Scenarios

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

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

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

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

***For weather conditions used in calculating fire behavior**, the electrical corporation must use probabilistic scenarios based on a 30-year history of fire weather. This approach must consider a range of wind speeds, directions, and fuel moistures that are representative of historic conditions. In addition, the electrical corporation must discuss how this weather history is adapted to align with current and forecasted climate conditions. The electrical corporation must consider the following two conditions:*

- ***Weather Condition 1 – Anticipated Conditions** – The statistical weather analysis is limited to fire seasons expected to be the most relevant to the next three years of the WMP cycle.*
- ***Weather Condition 2 – Long-Term Conditions** – The statistical weather analysis is representative of fire seasons covering the full 30-year history.*

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

One possible approach to the statistical weather analysis for fire behavior is Monte- Carlo simulation of synthetic fire seasons in accordance with approaches presented by the United States Forest Service.13 However, the electrical corporation must justify the selection of locally relevant data for use in this approach (i.e., Remote Automated Weather Systems data or historic weather reanalysis must be locally relevant). The data and/or models the electrical corporation uses to establish locally relevant weather data for these designs must be documented in accordance with the weather analysis requirements described in Appendix B.

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

- ***Vegetation Condition 1 – Existing Fuel Load** – The wildfire hazard must be evaluated with the existing fuel load within the service territory, including existing burn scars and fuel treatments that reduce the near-term fire hazard.*
- ***Vegetation Condition 2 – Short-Term Forecasted Fuel** Load – The wildfire hazard must be evaluated considering the changes in expected fuel load over the 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.*

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

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

- *Identification of each design basis scenario (e.g., Scenario 1, Scenario 2)*
- *Components of each scenario (e.g., Weather Condition 1, Vegetation Condition 1)*
- *Purpose of each scenario*

Table 6-3 Summary of Design Basis Scenarios

Scenario ID	Design Scenario	Purpose	Reference
N/A	*N/A*	*N/A*	*N/A*

The following information was provided by Technosylva in response to the information requested in this section:

The WRRM analysis uses a subset of historical weather data to simulate wildfires on specific days, taking into account ignition points along utility assets. The resulting risk scores are then combined to provide a comprehensive assessment of the wildfire risk distribution. 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 WRRM 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.

Additional detail for the weather data selection process specific to BVES can be provided upon request.

6.3.2 Extreme-Event Scenarios/Uncertainty Scenarios

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

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

While the primary risk analysis is intended to be based on the design scenarios discussed in Section 6.3.1, the potential for high consequences from extreme events may provide additional insight into the mitigation prioritization described in Section 7.

The electrical corporation must provide a brief narrative on the extreme-event scenarios used in its risk analysis. The electrical corporation must describe these scenarios and their purpose in the analysis. In addition, the electrical corporation must provide a table summarizing the following information:

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

Table 6-4 Exemplar Summary of Extreme-Event Scenarios

Scenario ID	Extreme-Event Scenario	Purpose	Reference
N/A	N/A	N/A	See Statement following table

This is not currently a capability within the Technoslyva software program being offered to BVES. This is however a capability that could be offered in the future based on discussions with Technosylva. Accordingly, BVES has discussed the possibility of adding this service with Technosylva. BVES will monitor developments in this area to determine whether such an approach is reasonable and prudent for a utility with the size and risk profile of Bear Valley.

6.4 Risk Analysis Results and Presentation

In this section of the WMP, the electrical corporation must present a high-level overview of the risks calculated using the approaches discussed in Section 6.2 for the scenarios discussed in Section 6.3.

The risk presentation must include the following:

- *Summary of electrical corporation-identified high fire threat areas in the service territory*
- *Geospatial map of electrical corporation-identified areas with heightened risk of fire in the service territory*
- *Narrative discussion of proposed updates to HFTD*
- *Tabular summary of top risk-contributing circuits across the service territory*
- *Tabular summary of key metrics across the service territory*

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

6.4.1 Top Risk Areas within the HFRA

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

BVES does not have any self-identified HFRAs that are outside the CPUC's HFTD. BVES will continue to assess if the HFTD-2 and HFDT-3 boundaries need adjustment in 2023.

6.4.1.1 Geospatial Maps of Areas with Heightened Risk of Fire

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

The maps must fulfill the following requirements:

- ***Risk levels:*** *Levels must be selected to show at least three distinct levels, with the values based on the following:*
- *Top 5 percent of overall utility risk values in the HFRA*
- *Top 5 to 20 percent of overall utility risk values in the HFRA*
- *Bottom 80 percent of overall utility risk values in the HFRA*
- ***Colormap*** *– The colormap of the contour must meet accessibility requirements (recommended colormap is Viridis)*
- ***County lines*** *– The map must include county lines as a geospatial reference*
- ***HFTD tiers*** *– The map must show a comparison with existing HFTD tier 2 and tier 3 regions.*

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. BVES will monitor developments in this area to determine whether such an approach is reasonable and prudent for a utility with the size and risk profile of Bear Valley.

6.4.1.2 Proposed Updates to HFTD

In this section, the electrical corporation must discuss the differences between the electrical corporation-identified areas with heightened fire risk and the existing Commission-approved HFTD. The electrical corporation must identify areas that its risk analysis indicates are at a higher risk than indicated in the current HFTD. The electrical corporation must also describe its proposed process to submit proposed changes to the Commission to modify the HFTD. The electrical corporation need not conclude that the HFTD should be expanded and/or modified. Any proposed changes to the HFTD must be mapped in accordance with the requirement in the previous sub-section.

Currently, BVES does not see a need for any changes to the HFTD designations for the Bear Valley service territory of which nearly all of 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.

6.4.2 Top Risk-Contributing Circuits/Segments/Spans

The electrical corporation must provide a summary table showing the highest-risk circuits/segments14 within its service territory. The table should include the following information about each circuit:

- ***Circuit, Segment, or Span ID*** *– unique identifier for the circuit, segment, or span*
- ***Overall Utility Risk Scores*** *– numerical value for each risk*
- ***Top Risk Contributors*** *–the risk components that lead to the high risk on the circuit*

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

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

Table 6-5 Summary of Top-Risk Circuits/Segments

Risk Ranking	Circuit/Segment ID	Overall Risk Score	Ignition Risk Score	PSPS Risk Score	Top Risk Contributors
1	Radford	31214.88	60	30	31215
2	Shay	3524.496667	30	60	3524
3	Baldwin	6890.98	30	60	6891
4	Boulder	882.12	30	30	882
5	North Shore (Fawnskin)	6717.236667	30	30	6717
6	Pioneer (Palomino)	2729.88	30	30	2730
7	Clubview	3225.04	30	30	3225
8	Goldmine	4538.8	30	30	4538
9	Paradise	1809.546667	30	30	1810
10	Sunset	2373.52	30	30	2374
11	Sunrise (Maple)	1856.69	30	30	1857
12	Holcomb (Bear City)	4746.15	30	30	4746
13	Georgia	1384.19	30	30	1384
14	Eagle	1812.686667	30	30	1813
15	Garstin	1366.31	30	30	1366
16	Lagonita	1533.14	30	30	1533
17	Interlaken	1485.16	30	30	1485
18	Castle Glen (Division)	1483.32	30	30	1483

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

BVES already identifies and maps its highest risk circuits through its the Fire Safety Circuit Matrix. This risk is further understood through the use of BVES's other risk assessment, modeling and mapping tools including the Technosylva products procured by Bear Valley. With the implementation of Technosylva's model, BVES will perform these calculations and expects to have them available in its 2024 WMP Update.

6.4.3 Other Key Metrics

The electrical corporation must calculate, track, and present on several other key metrics and indicators of risk across its service territory (see Appendix B for additional information on the calculation of these metrics). These include, at a minimum:

- ***High 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. The electrical corporation must specify whether it calculates its own FPI or uses an external source, such as the United States Geological Survey.*
- ***Red Flag Warning (RFW)*** *– Near-term proxy for the potential of high wildfire risk due to weather conditions, as declared by the National Weather Service (NWS)*
- ***High Wind Warnings (HWW)*** *– Near-term potential for high wind risk, as declared by the NWS*

For each metric, the frequency of its occurrence within each HFTD tier and the HFRA must be reported in the table below. The metric must be reported in number of overhead circuit mile (OCM) days of occurrence normalized by circuit miles within that area type. For example, consider an electrical corporation with 1,000 OCM in HFTD Tier 3. If

100 of these OCM are under a RFW for one day, and 10 of those OCM are under a RFW for an additional day, then the average RFW-OCM per OCM would be:

$$RFW\_OCM/OCM = (100 \times 1 + 10 \times 1)/1000 = 0.1$$

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

Table 6-6 Summary of Key Metrics by Statistical Frequency Exemplar

Metric	Non-HFTD	HFTD Tier 2	HFTD Tier 3
FPI-OCM/OCM	0.XX	0.XX	0.XX
RFW-OCM/OCM	0.XX	0.XX	0.XX
HWW-OCM/OCM	0.XX	0.XX	0.XX

BVES has tracked and recorded Red Flag Warning (RFW) and High Wind Warning (HWW) for its 2023-2025 WMP and previous WMPs and continues to record it in its QDR. All of BVES's service territory resides in Tier 2 and Tier 3. BVES installed several remote weather stations and uses a contract meteorologist that tracks this information from the National Weather Service, the installed weather stations, the National Fire Danger Rating System (NFDRS), and other key indicators. Additionally, High Wind Warning and Red Flag Warning as well as other real-time climactic features are incorporated into Technosylva's real-time risk mapping of BVES's territory.

6.5 Enterprise System for Risk Assessment

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

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

With the implementation of Technosylva's models, BVES will pull together a risk enterprise system and expects show significant progress in its 2024 WMP Update.

6.6 Quality Assessment and Control

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

- *Independent review – Role of independent third-party review in the data and model quality assessment*

- *Model controls, design, and review – Overview of the quality controls in place on electrical corporation risk models and sub-models*

6.6.1 Independent Review

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

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

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

As BVES has contracted Technosylva to be its risk model provider BVES defers to the independent review results (Guide ASTM E 1355) that are 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 are able to 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 modelling 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 on-going research, testing, validation and implementation of both models and data sources.

6.6.2 Model Controls, Design, and Review

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

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

- ***Modularization** – The electrical corporation must evaluate its software architecture to ensure the structure is sufficiently modular to track and control changes and enhancements over time. At a minimum, the electrical corporation risk model is expected to have separate modules to evaluate each of the following:*
- *Weather analysis*
- *Fire behavior analysis*
- *Seasonal vegetation analysis*
- *Equipment failure*
- *Exposure and vulnerability analysis*
- ***Reanalysis** – The electrical corporation must maintain the capability to provide Energy Safety the results of its risk model based on the operational version of the software (including code and data) on a specific historic day.*
- ***Version control** – The electrical corporation must use industry standard practices in version controlling its risk model and sub-models. At a minimum, the electrical corporation is expected to meet the following requirements:*
- *Models and software must use version controls aligned with industry standard programs, procedures, and protocols.*
- *Model input data, including geospatial data layers, must be version controlled.*
- *Technical, verification, and validation documentation must be periodically updated for new software versions.*

- *Procedures for updating technical, verification, and validation documentation.*

Per the engagement agreement, and the description above in Section 6.6.1, Technosylva maintains that it meets all the requirements set forth by Energy Safety in this section.

6.7 Risk Assessment Improvement Plan

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

- ***Risk assessment methodology** – Wildfire and PSPS risk assessment methodology and its documentation, including both quantitative and qualitative approaches*
- ***Design basis** – Justification of design basis scenarios used to evaluate the risk and its documentation*
- ***Risk presentation** – Presentation of risk to stakeholders, including dashboards and statistical assessments*
- ***Risk event tracking** – Tracking and reconstruction of risk events and integration of lessons learned*

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

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

In addition, the electrical corporation must provide a more detailed description of its proposed improvement plan in Appendix B. This must consist of a concise narrative (maximum of five pages per improvement) summarizing:

- ***Problem statement** – Description of the current state of the problem to be addressed*
- ***Planned Improvement** – Discussion of the planned improvement, including any new/novel strategies to be developed and the timeline for their completion*
- ***Anticipated Benefit** – Description of the anticipated benefit of the improvement to the electrical corporation's program and risk in its service territory*
- ***Region prioritization (where relevant)** – Reference to risk-informed analysis (e.g., local validation of weather forecasts in the HFTD) demonstrating that high-risk areas are being prioritized for continued improvement*
- *Supporting documentation (as necessary)*

Table 6-7 Utility Risk Assessment Improvement Plan

Key Risk Assessment Area	Proposed Improvement	Type of Improvement	Expected Value Added	Timeframe and Key Milestones

The implementation of Technosylva and its modeling software is currently underway. BVES believes that until the full suite of tools purchased is available and utilized, it is not in its best interest to develop an Improvement Plan for its Risk Assessment Program. Once BVES gains experience generating the appropriate outputs, and conducts its own analysis on those outputs, BVES will be better positioned to determine areas of improvement going forward.

7. Wildfire Mitigation Strategy Development

In this section of the WMP, the electrical corporation must provide a high-level overview of its risk evaluation and process for deciding on a portfolio of mitigation initiatives to achieve maximum feasible4.1–4.2, and wildfire mitigation strategy for 2023-2025. Sections 7.1 and 7.2 below provide detailed instructions. 16 risk reduction and that meet the goal(s) and plan objectives stated in Sections

7.1 Risk Evaluation

7.1.1 Approach

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

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

Currently, uses a 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 of April 25, 2019. BVES then further evaluates enterprise risk using its Fire Safety Circuit Matrix to prioritize wildfire risk. BVES has also evaluated risk due to safety, reliability, and loss of energy supply threshold risk to account for differentiating threats within the service area.

Additionally, BVES enhanced its ignition risk mapping methodology with the completion of several ignition probability models in 2021 through an expert consultant (REAX Engineering). The model results aimed to better predict, quantify, and measure risk drivers across all initiatives under high-risk and climate change related metrological forecasts. The risk maps that were developed provide ignition probability, consequence (area impact and structure impact), and risk under current conditions and future (2050) conditions so that the effects of climate change may be better understood and incorporated into BVES's planning.

In June of 2022, BVES contracted with Technosylva to further advance the Risk Mapping Program and enhance situational awareness. Better understanding of the risk environment will improve BVES's resource allocation. This effort will leverage Technosylva's Wildfire Analyst Enterprise (WFA-E) software capabilities and solutions implemented across California for other electric utility companies. Engaging with Technosylva will provide BVES software applications and analysis to generate the following:

- Through use of WFA-E FireSim, provision of on-demand, real time wildfire behavior modeling, predictive spread conditions, and derivation of potential impacts analysis
- Ability to conduct simulations on-demand, to reflect changing conditions or local data observations, including proactive "what if" scenarios
- Weather and wildfire risk forecasting for customer assets and the service territory using daily weather prediction integration to support PSPS activation calls and response operations
- Asset risk analysis using historical weather climatology to support WMP development and mitigation planning

The asset risk analysis will utilize Technosylva's Wildfire Risk Reduction Model (WRRM) which uses historical climatology (weather & fuel moisture data) as key input weather scenarios (~ 30 year and 2 km hourly re-analysis data). The model produces risk metrics by running fire spread simulations for each weather scenario territory wide. The outputs can be aggregated based on percentile and assigned to assets. The model uses historical or predicted fuels data (2030 etc.) and utilizes hundreds of millions of fire spread simulations across customer service territory. The outputs are to be used to support mitigation planning in addition to setting context for daily FireCast asset risk forecasts.

It is BVES's intent to transition from using the Fire Matrix to use the WRRM to prioritize its WMP initiatives. The first runs of the WRRM were not completed in time to plan the 2023 WMP grid hardening work plan, since much of the planning occurred in the summer of 2022. Initial WRRM results became available to BVES in late February 2023. Therefore, the WRRM will be used in the 2024 and 2025 WMP Updates. BVES believes that replacing the Fire Matrix with the WRRM will provide a probabilistic model at the circuit and segment levels of granularity. The model will provide calculated probability, consequence, and risk.

<u>Enterprise Risk Mitigation Strategy</u>

BVES maintains a risk mitigation strategy to prioritize operationally effective strategies for risk reduction. The methodology identifies inherent risk, existing controls, residual risk, and future mitigation efforts after determining the likelihood and impact of wildfire risk in the service territory. This is the primary risk evaluation tool utilized to prioritize and plan for WMP initiatives. BVES's Risk-Based Decision-Making Framework is consistent with other SMJUs based on direction from the Commission. Figure 7-1, below, provides an overview of the steps.

Figure 7-1 BVES Risk-Based Decision-Making Framework

The BVES Risk Register Model evaluates the enterprise risk reduction relative to the cost of the mitigation using a RSE analysis. This analysis focuses on a review of ongoing and potential new projects to mitigate the three primary wildfire risk events:

- Wildfire Public Safety
- Wildfire – Significant Loss of Property
- Loss of Energy Supplies

The enterprise risk evaluation considers a reasonable worst-case scenario for the three primary wildfire risk events. For each primary risk event, BVES determined the frequency of occurrence and impact scores for each of the weighted risk scoring inputs listed below:

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

- Environmental impacts

The Risk Register Model quantifies mitigation projects and programs by the risk benefit and risk spend efficiency (RSE). This allows BVES to better evaluate projects in terms of risk reduction and select the most cost-effective and efficient project among alternatives. BVES utilizes a 7x7 log score model 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 or risk benefit for each scoring input to arrive at a weighted mitigated risk score. The risk benefit for each combination of mitigation activity 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.

Fire Safety Circuit Matrix

The Fire Safety Circuit Matrix aims to characterize each BVES distribution circuit into high, moderate, and low wildfire risk and then prioritize the circuits within each wildfire risk group. To meet this objective, BVES developed a balanced scorecard approach with the use of a Fire Safety Circuit Matrix. The matrix data inputs include, inter alia, 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 wildfire risk mitigation score. Currently, seven circuits are rated high risk, 12 circuits are rated moderate risk, and seven circuits are rated low risk.

In addition to evaluating the risk reduction and RSE, BVES must account for the timing and proper sequencing of the various wildfire mitigation initiatives. For example, while the Situational Awareness Enhancement Project (establishing a distribution management center) offers a relatively high RSE, it cannot be fully completed until various grid automation initiatives are completed in 2025.

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- and 10-year targets for the reduction of the wildfire mitigation score and associated wildfire ignition risk reduction.

The risk evaluation approach in this WMP is designed to meet a range of industry-recognized standards, best practices, and research to determine a wildfire and PSPS risk mitigation strategy. The intent is to use this approach to help inform BVES’s development of a portfolio of wildfire mitigation initiatives and activities that meet the goals and objectives stated in Sections 4.1–4.2. Therefore, BVES’s general risk evaluation approach consists of the following:

- Identification of key stakeholder groups, decision-making roles and responsibilities, and engagement process.
- Identifying risk evaluation criteria based on the balance of various performance goals. Applying the criteria to monitor the effectiveness of the electrical corporation’s WMP in achieving its identified goals and objectives.

- Evaluating wildfire and PSPS risks and risk components described in Section 4 against the risk evaluation criteria, considering both potential positive and potential negative outcomes. Applying the results from the evaluation of wildfire and PSPS risks within BVES's service territory within a risk-informed decision-making process to develop prioritized areas where mitigation initiatives are necessary.
- Identifying a portfolio of wildfire mitigation initiatives and activities, prioritized by risk. Identifying and characterizing potential mitigation approaches for each.
- Performing an integrated evaluation of the identified potential risk mitigation initiatives. The outcome is the specification of a portfolio of mitigation initiatives that will be implemented over the WMP cycle.
- Providing a summary of the approved risk mitigation strategies for inclusion in the WMP submission. The summary includes schedules for implementation of the strategies, procedures for management oversight of implementation of the mitigations, and methods of evaluation of their effectiveness once deployed.
- Discussing the expected improvements in maturity and describing monitoring activities to assess the degree of improvement in the targeted maturity.

7.1.2 Key Stakeholders for Decision Making

In this section, the electrical corporation must identify all key stakeholder groups that are part of the decision-making process for developing and prioritizing mitigation initiatives. At a minimum, the electrical corporation must do the following:

- *Identify each key stakeholder group (e.g., electrical corporation executive leadership, the public, state/county public safety partners)*
- *Identify the decision-making role of each stakeholder group (e.g., decision maker, consulted, informed)*
- *Identify method of engagement (e.g., meeting, workshop, written comments)*

The electrical corporation must also describe how it communicates decisions to the identified key stakeholders.

In the below section BVES identifies all key stakeholder groups that are part of the decision-making process for developing and prioritizing mitigation initiatives. The roles and responsibilities for the BVES decision making process for communicating with the identified key stakeholders can be seen in Table 7-1.

Table 7-1 Stakeholder Roles and Responsibilities in Decision Making Process

Stakeholder	Stakeholder Point of Contact	Electrical Corporation Point of Contacts	Stakeholder Role	Engagement Protocols
Sheriff's Department Big Bear Lake Patrol Station	Sherriff	Paul Marconi	• Evacuation Routes • PSPS Coordination	• Phone calls as needed • Quarterly public meetings

Big Bear Fire Department	Fire Chief	Paul Marconi	• Policy • Coordinate emergency response • Wildfire mitigation	• Quarterly meetings • As needed phone calls
San Bernadino County	Big Bear Lake Representative for County Supervisor 3rd District	Paul Marconi	• Policy • Communication	• Bi-annual meetings • Phone calls as needed
Cal Trans	Transportation Engineer	Tom Chou	• Grid hardening coordination • PSPS coordination • Permitting	• Quarterly meetings • Phone calls as needed
City of Big Bear Lake	City Manager Director of Public Service/City Engineer	Paul Marconi Jon Pecchia	• Policy • Permitting • Communication	• Quarterly public meetings • Phone calls as needed
Mountaintop San Bernadino US Forrest Service	District Ranger	Jon Pecchia	• Grid hardening coordination • Vegetation management • Permitting	• Phone calls as needed

7.1.3 Risk-Informed Prioritization

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

In this section, the electrical corporation must:

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

For each of the risk scenarios discussed in Section 6.2, BVES developed an initial prioritization list based solely on quantitative risk. 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.

From this geospatial prioritization of quantitative risk, BVES developed a prioritized list of risks for which it will investigate and develop potential mitigation initiatives.

BVES' higher fire-threat areas outlined below and prioritized activities for this current WMP cycle include the following circuits: (1) Radford, (2) Baldwin, (3) Shay, (4) Northshore, (5) Goldmine, (6) Holcomb (Bear City), and (7) Clubview.

Table 7-2 Evaluation of HFTD Prioritized Circuits

Circuit	Substation	Wildfire Risk Group	Overall Risk Weighting	Risk Ranking	Voltage (kV)	High Fire Threat District Tier	Vegetation Density	Wind Intensity	# of Customers	# of Wood Poles	# of Fire Resistant Composite Poles	# of LWS Poles	# of Ductile Iron Poles	Bare Wire OH Circuit Miles	Covered Conductor OH Circuit Miles	UG Circuit Miles
Radford	SCE Feed	31215	0.3826	1	34.5	3	High	High	3487	89	0	0	0	2.82	0	0.02
Shay	SCE Feed	3524	0.0432	6	34.5	2	Medium	High	5982	586	0	24	0	5.57	11.6	0.39
Baldwin	SCE Feed	6891	0.0845	2	34.5	2	Medium	High	11621	236	0	20	0	7.62	1.32	0.5
Boulder	Village	882	0.0108	18	4.16	2	Medium	High	2085	530	22	6	0	17.28	0.4	1.8
North Shore (Fawnskin)	Fawnskin	6717	0.0823	3	4.16	2	High	High	1512	524	0	0	0	15.83	0	8.09
Erwin Lake	Maltby	0	-0.0030	26	4.16	2	Medium	High	2574	1064	2	6	0	15.5	5.83	7.41
Pioneer (Palomino)	Palomino	2730	0.0335	8	4.16	2	Medium	High	534	601	0	1	0	11.22	5.17	2.95
Clubview	Moonridge	3225	0.0395	7	4.16	2	High	Medium	1723	507	3	2	0	9.76	0.42	0.27
Goldmine	Moonridge	4539	0.0556	5	4.16	2	Medium	High	2083	601	0	0	0	13.2	0	5.26
Paradise	Maltby	1810	0.0222	12	4.16	2	Medium	High	1874	532	3	17	0	7.22	2.63	2
Sunset	Maple	2374	0.0291	9	4.16	2	High	Medium	1894	505	0	0	0	8.38	2.29	0.5
Sunrise (Maple)	Maple	1857	0.0228	10	4.16	2	Medium	Medium	1772	348	0	0	0	7.61	0.18	3.86
Holcomb (Bear City)	Bear City	4746	0.0582	4	4.16	2	Medium	High	1581	609	2	4	0	13.15	0.1	0.85
Georgia	Pineknot	1384	0.0170	16	4.16	2	Medium	Low	586	349	0	0	0	5.91	0	3.95
Eagle	Pineknot	1813	0.0222	11	4.16	2	Medium	Medium	689	323	0	0	0	7.38	0	1.53
Hamish (Village)	Village	786	0.0096	19	4.16	2	Medium	Low	327	85	0	0	0	1.34	0	1.21
Garstin	Meadow	1366	0.0167	17	4.16	2	High	Low	1347	277	0	0	0	5.09	0.82	3
Lagonita	Village	1533	0.0188	13	4.16	2	Medium	Low	1085	452	1	0	0	7.46	0	1.43
Interlaken	Meadow	1485	0.0182	14	4.16	2	Medium	Medium	889	280	0	0	0	6.04	0.41	3.56
Castle Glen (Division)	Division	1483	0.0182	15	4.16	2	Medium	High	1216	340	9	2	0	5.38	1.6	3.68
Country Club	Division	640	0.0078	20	4.16	2	Medium	Medium	586	178	1	0	0	3.08	0.15	0.94
Fox Farm	Meadow	0	0.0000	25	4.16	2	Low	Low	28	2	0	0	0	0	0	0.84
Pump House (Lake)	Lake	202	0.0025	22	4.16	2	Low	High	3	22	0	0	0	0.64	0	0.02
Lift (Summit TOU)	Summit	627	0.0077	21	4.16	2	Low	Low	0	1	0	0	0	0.1	0	0
Skyline (Summit Res)	Summit	0	0.0000	23	4.16	2	Low	Low	0	0	0	0	0	0	0	0
Geronimo (Bear Mtn.)	Bear Mtn.	0	0.0000	23	4.16	2	Low	Low	2	0	0	0	0	0	0	0.03

Wildfire Risk Groups
High
Moderate
Low

Figure 7-2 Prioritization of Higher Fire-Threat Areas

Known Local Condition

With relation to (General Order) GO 95 Rule 31.1, BVES adheres to requirements listed for its design, construction, and maintenance activities within a safe and prudent manner. In some instances, BVES exceeds GO 95 standards such as with vegetation right-of-way (ROW) management utilizing an internal company standard of 72-inch minimum radial clearance specification. With respects to operating its system, BVES monitors meteorological conditions through its situational awareness program, including the use of live data feeds from its own weather stations and visual feeds through the ALERTWildfire network of high-definition (HD) cameras.

BVES's service area is entirely above 3,000 feet requiring all construction to conform to the heavy loading standards of GO 95. The heavily forested environment and mountainous terrain makes the territory vulnerable to potential ignition risk. Per GO 95 21.2 and D. 17-12-024, the entire service area is within the HFTD Tiers 2 and 3, requiring BVES to manage its assets with an understanding of elevated hazards for ignition risk. This includes high wind activity, excessive fuel loading, and lower humidity during the summer months. BVES's service territory also experiences heavy winter loading. BVES maintains and operates its equipment with an abundance of caution due to the seasonal conditions, which may impact delivery of power. While BVES's service territory has not experienced a recorded utility-ignition event in recent history, field workers assume variable risks when engaging in line maintenance and construction. In accordance with GO 166 Standard 1.E, BVES performs activities with safety as a principal focus as part of its Fire Prevention Plan and company standards.

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 the risk team with 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 model incorporates a risk-based decision-making framework into utility investments and programs to inform the General Rate Case (GRC) cycles. The risk-based decision-making framework provides a process for identifying asset-related risks, consequences of occurrence, frequency or likelihood of occurrence, risk drivers, and mitigation measures. This framework considers BVES's distribution assets and its Bear Valley Power Plant (BVPP). The results of the model aim to identify strategic objectives for approval, categorize top risks to BVES and its service area including new and emerging risks, and arriving at a risk-informed recommendation for future investments. This may also lead to modifying existing controls and implementation schedules.

Data Elements:

Scope and granularity: Data includes incident and safety findings, identified risk events with consequence mapping, field findings, and external sources of risk. These drivers are updated annually as new inputs are collected.

Frequency of data updates: Updates to the risk model occur on an annual basis to help determine any needed changes for capital investment or enhanced O&M activities.

Sources of data: The initial list of risk events is captured through record-keeping practices and risk team brainstorming sessions. These risks are reviewed and categorized with links to asset classes and affixed with a priority weight for the initial analysis. Additional inputs include activities poised to reduce the identified risk weight through WMP and operational execution.

The raw data includes scores for frequency, reliability, compliance, quality of service, safety, environmental, and impact score, which result in the total risk score.

Detailed approaches used to verify data quality: Data quality is verified through brainstorming sessions, SME input, and annual review of the model outputs. The data aligns with similarly tracked information imperative to the WMP update and quarterly reports. BVES ensures there is a 1-1 relationship between the inputs and outputs of the model across all enterprise risk practices. The System Safety and Reliability Engineer is also responsible for reporting any findings or discrepancies among the tracked data values and outputs. This employee also assists in quantifying the impact scores for the proposed mitigations and existing controls.

7.1.4 Mitigation Selection Process

After the electrical corporation creates a list of top-risk contributing circuits/segments/spans (Section 6.4.2) and prioritized areas based on overall utility risk (Section 7.1.3), the electrical corporation must then identify potential mitigation strategies. It must also evaluate the benefits and drawbacks of each strategy at different scales of application (e.g., circuit, circuit segment, system-wide). In this section of the WMP, the electrical corporation must provide the basis for its decisions regarding which mitigation initiatives to pursue. It must also document how it develops, evaluates, and selects mitigation initiatives.

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

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

The electrical corporation may also mitigate risk by combining multiple mitigation initiatives. The electrical corporation is expected to use its procedures discussed in Section 7 to:

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

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

BVES determines potential mitigation strategies based on the comprehensive 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.

Identification of Potential Projects: This step is designed to identify and determine which projects are potentially viable to deliver consequential wildfire risk reduction. The outcome of this step 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 is calculated using the Risk-Based Decision-Making process. For BVES to obtain a reasonable assessment of the risk reduction and RSE for each project, BVES always seeks to understand to what degree will the risk reduction work be achieved and, if achievable or partly achievable and 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 going back to the Risk-Based Decision-Making model for SMJUs. From this analysis, RSE is calculated.

7.1.4.1 Mitigation Initiatives Development Process

The electrical corporation must describe how it identifies and evaluates options for mitigating wildfire and PSPS risk at various analytical scales. The current guidelines governing this process are derived from the Risk-Based Decision-Making Framework established in the Safety Model and Assessment Proceeding (S-MAP). The S-MAP is currently being updated in CPUC proceeding R. 20-07-013. In due course, the electrical corporation's risk mitigation identification procedure must align with results from this proceeding.21 The electrical corporation must describe the following:

- *The procedures for identifying and evaluating mitigation initiatives (comparable to 2018 S-MAP Settlement Agreement, row 26), including the use of risk buy-down estimates (e.g., risk-spend efficiency) and evaluating the benefits and drawbacks of mitigations*

- *To the extent possible, multiple potential locally relevant mitigation initiatives to address local wildfire risk drivers (see 2018 S-MAP Settlement Agreement, row 29)*
- *The approach the electrical corporation uses to characterize uncertainties and how the electrical corporation's evaluation and decision-making process incorporates these uncertainties (see 2018 S-MAP Settlement Agreement, rows 29 and 30)*
- *Two or more potential mitigation initiatives for each risk driver included in the list of prioritized areas (Table 7-2 in Section 7.1.3), including the following information:*
- *The initiatives and activities*
- *Expected risk reduction and impact on individual risk components*
- *Estimated implementation costs*
- *Relevant uncertainties*
- *Implementation schedule*
- *How the electrical corporation uses multi-attribute value functions (MAVFs) and/or other specific risk factors (as identified in 2018 S-MAP or subsequent relevant CPUC Decisions) in evaluating different mitigations*

BVES process and procedures to evaluate options for mitigating wildfire and PSPS risk at various analytical scales is discussed in Section 7.1.1. 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. 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.

7.1.4.2 Potential Mitigation Initiative Evaluation and Selection

After identifying and characterizing the mitigation options, the electrical corporation must analyze the options to determine which will reduce risk the most, given limitations and constraints (e.g., resources available for mitigation initiatives). To the greatest extent practicable, the electrical corporation must make these determinations using its existing framework of project prioritization. The electrical corporation must strive to optimize its resources for maximum risk reduction.

The electrical corporation should seek the best integrated portfolio of mitigation initiatives to meet its performance objectives. Objectives may be based on quantified risk assessment results (see Section 6), or other values prioritized by the electrical corporation or broader stakeholder groups (e.g., environmental protection, public perception, resilience, cost). At a minimum, the electrical corporation must do the following:

- *Evaluate its potential mitigation initiatives. This evaluation will yield a prioritized list of initiatives. The objective is for the electrical corporation to identify the preferable initiatives for specific geographical areas. (Comparable to 2018 S-MAP Settlement Agreement, rows 12, 26, and 29.)*
- *Identify the best mitigation initiatives for all geographical areas to create a portfolio of projects expected to provide maximal benefits within known limitations and constraints. (Comparable to 2018 S-MAP Settlement Agreement, rows 12, 26, and 29.)*
- *Explain how the electrical corporation is optimizing its resources to maximize risk reduction. Describe how the proposed initiatives are an efficient use of electrical corporation resources and focus on achieving the greatest risk reduction with the most efficient use of funds and workforce resources.*

This process is expected to be iterative due to the competing nature of performance objectives and their complex interrelationships.

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

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

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

Selection of Projects: In this step, management uses the information developed in the prior step to identify the optimal mix of projects to be included in the WMP (and follow-on updates to the WMP) to deliver maximum risk reduction. This process also includes re-evaluating multi-year projects that are in progress to determine if they should be continued or discontinued. The expected outcome of this step is to develop an integrated and prioritized list of WMP projects to be developed and 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 process 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 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 Reax Engineering and Technosylva to determine where the wildfire mitigation greatest risk benefit may be achieved by each project.

7.1.4.3 Mitigation Initiative Scheduling Process

The electrical corporation must report on its schedule for implementing its portfolio of mitigation initiatives. The electrical corporation must describe its preliminary schedules for each initiative and its iterative processes for modifying mitigation initiatives (Section 7.1.4.1).

Mitigation initiatives may require several years to implement. For example, relocating transmission or distribution capabilities from overhead to underground may require substantial time and resources. Since mitigation initiatives are undertaken in high-risk regions, the electrical corporation may need interim mitigation initiatives to mitigate risk while working to implement long-term strategies. Some examples of interim mitigation initiatives include more frequent inspections, fire detection and monitoring activities, and PSPS usage. If the electrical corporation's mitigation initiative requires substantial time to implement, the electrical corporation must identify and deploy interim mitigation initiatives as described in Section 7.2.3.

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

- *How the electrical corporation schedules mitigation initiatives.*

- *How the electrical corporation evaluates whether an interim mitigation initiative is needed and, if so, how an interim mitigation initiative is selected (see Section 7.2.3).*
- *How the electrical corporation monitors its progress toward its targets within known limitations and constraints. This should include descriptions of mechanisms for detecting when an initiative is off track and for bringing it back on track.*
- *How the electrical corporation measures the effectiveness of mitigation initiatives (e.g., tracking the number of protective equipment and device settings de-energizations that had the potential to ignite a wildfire due to observed damage/contact prior to re-energization). The mitigation sections of these Guidelines (Sections 8) include specific requirements for each mitigation initiative.*

Sequencing of Projects:

BVES management uses the information developed in the prior step 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 ready 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 7.1.1 of this WMP and the Risk Maps. As detailed in Section 5, 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 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.

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

7.2 Wildfire Mitigation Strategy

In this section, BVES provides an overview of its proposed wildfire mitigation strategies based on the evaluation process identified in Section 7.1.

7.2.1 Overview of Mitigation Initiatives

The electrical corporation must provide a high-level summary of the portfolio of mitigation initiatives across its service territory. In addition, the electrical corporation must describe its reasoning for the proposed portfolio of mitigation initiatives and why it did not select other potential mitigation initiatives.

Additionally, for each mitigation initiative category, the electrical corporation must provide the following:

- *A high-level overview of the selected mitigation initiatives*
- *An implementation plan, including its schedule and how progress will be monitored*
- *How the need for any interim mitigation initiatives was determined and how interim mitigation initiatives were selected (see Section 7.2.3)*

BVES' high-level summary of mitigation initiatives across its service territory include geospatial areas where mitigation will be deployed, levels at which mitigation will be deployed, and brief descriptions of the scope of mitigation.

The three-year objectives include the annual WMP update objectives with the additional grid hardening efforts, increased situational awareness and control improvements expected from completion of the grid automation initiatives, real-time fire risk modeling, and increased resiliency to serve load via local generation through potential 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.

The ten-year objectives include significant reduction of wildfire ignition probability and improved system resilience. Much of this will stem from BVES's grid hardening efforts. BVES expects to fully realize the benefits from its various grid automation initiatives and its proposed solar and storage projects. BVES's long-term grid hardening will primarily be aimed at continuing to replace bare wire with covered wire on its sub-transmission and distribution systems. This project will continue over the next ten years addressing the highest risk circuits first. Additionally, in the next ten years, BVES will look to leverage the fiber network installed in its service area with new technologies in monitoring equipment, systems, and external conditions and bringing this data to databases to be utilized in risk determination (perhaps real-time) and to improve situational awareness of operational staff. Specific technologies and sensors will be considered over the next few years and may be included in future WMPs if warranted. BVES will also work to continue automating switches and equipment where feasible and beneficial to mitigate wildfire risk.

BVES's implementation strategy for each mitigation initiative selected in accordance with the risk-informed process discussed in Section 7.1, is displayed in Table 7-3 below.

Table 7-3 BVES WMP Mitigation Initiatives for 3-year and 10-year Outlooks

WMP Category	Within 3 Years	Within 10 Years	Location in WMP
Grid design, operations, and maintenance	• Replace all sub-transmission (34.5 kV) overhead bare conductors with covered conductors • Assess and remediate all sub-transmission (34 kV) poles • Harden secondary evacuation routes in highest risk areas • Remove all tree attachments from high risk areas • On a priority basis, automate substations, switches, field devices, and fuse tripsavers and connect to SCADA • Replace Capacitor Banks and Connect to SCADA • Pursue development and execution of the Bear Valley Solar Energy Project • Pursue development and execution of the Energy Storage Project	• Replace all high and medium risk distribution (4 kV) overhead bare conductors with covered conductors • Assess and remediate all high and medium risk distribution (4 kV) poles • Harden secondary evacuation routes • Remove all tree attachments from distribution system • Automate remaining substations, switches, field devices, and fuse tripsavers and connect to SCADA • Replace remaining Capacitor Banks and Connect to SCADA • Pursue other renewable generating facility opportunities • Pursue other energy storage project opportunities • Assess emerging technologies aimed at early detection of asset degradation, wire down detection, and other ignition	Section 8.1

	• Upgrade highest risk substations • Continue robust asset inspection routine of annual Detailed Inspections, Patrol Inspections, LiDAR surveys, UAV HD Photography & Thermography, 3rd party Ground Patrols, Intrusive Pole Testing, and Substation Inspections • Implement robust asset management and inspection enterprise system. • Improve quality assurance and quality control program on asset work and asset inspection.	prevention/mitigation technologies • Assess other emerging sub-transmission and distribution inspection techniques	
Community Outreach and Engagement	• Continue to deploy and improve 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. Evaluate effectiveness of outreach efforts. • Continue to improve program to understand, evaluate, design,	• Implement social media and other effective platforms to increase 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. Evaluate effectiveness of these outreach efforts. • Establish streamlined routine for sharing lessons learned and	Section 8.5

	and implement wildfire and PSPS risk mitigation strategies, policies, and procedures specific to access and functional needs customers. Evaluate effectiveness of these efforts. • Work with stakeholders to develop and integrate 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. Evaluate effectiveness of these collaborative efforts. • Continue to be proactive in sharing and integration of best practices and collaborating with other electrical corporations on technical and programmatic aspects of WMP programs.	best practices among peers.	
Situational Awareness and Forecasting	• Complete online diagnostic pilot program and evaluate effectiveness. • Complete installation of fault	• Evaluate effectiveness of installing cameras, infrared detectors, LiDAR instruments, and other technologies on	Section 8.3

	indicators (FIs). Evaluate need for additional (FIs) • Evaluate need for additional weather stations. • Evaluate need for additional HD Alert Cameras. • Develop and implement Fire Potential Index. • Improve staff proficiency in utilizing advanced fire threat weather forecasting tools.	overhead assets to provide remote monitoring.	
Vegetation Management and Inspection	• Maintain enhanced clearance specifications and evaluate effectiveness • Continue to proactively remove/remediate high-risk species. • Continue robust vegetation inspection routine of annual Detailed Inspections, Patrol Inspections, LiDAR surveys, UAV HD Photography, 3rd party Ground Patrols, and Substation Inspections • Implement robust vegetation management and inspection enterprise system. Ensure all trees within right of way tracked in data system. • Improve quality assurance and quality control	• Continue to conduct program to promote vegetation communities that are sustainable, fire-resilient, and compatible with the use of the land as an electrical corporation right-of-way. • Evolve vegetation inspection cycles to be risk based • Evolve vegetation clearance cycles to be risk based	Section 8.2

	program on vegetation management inspection and clearance work and asset inspection. • Develop and implement program to promote vegetation communities that are sustainable, fire-resilient, and compatible with the use of the land as an electrical corporation right-of-way.		
Emergency Preparedness	• Improve staff training on emergency and disaster response plan through a combination of classroom instruction, tabletop exercises, and functional drills. • Increase coordination with community stakeholders in emergency response. • Develop robust lines and layers of communications with stakeholders and customers. • Integrate plan to restore service after an outage due to a wildfire or PSPS event. • Establish strong programs, systems, and protocols to support residential and non-residential	• Integrate emergency response plan with stakeholder emergency response plans • Evaluate increased use of social media and technology to improve and streamline communications with stakeholders and customers.	Section 8.4

	customers in wildfire emergencies and PSPS events.		

7.2.2 Anticipated Risk Reduction

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

The electrical corporation must provide:

- *Projected overall risk reduction*
- *Projected risk reduction on highest-risk circuits over the three-year WMP cycle*

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

7.2.2.1 Projected Overall Risk Reduction

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

BVES' overall service area risk reduction depicted in Figure 7-3 and Table 7-4 Projected Overall Service Territory Risk intends to provide an integrated view of wildfire risk reduction across its service territory over the next 10 years.

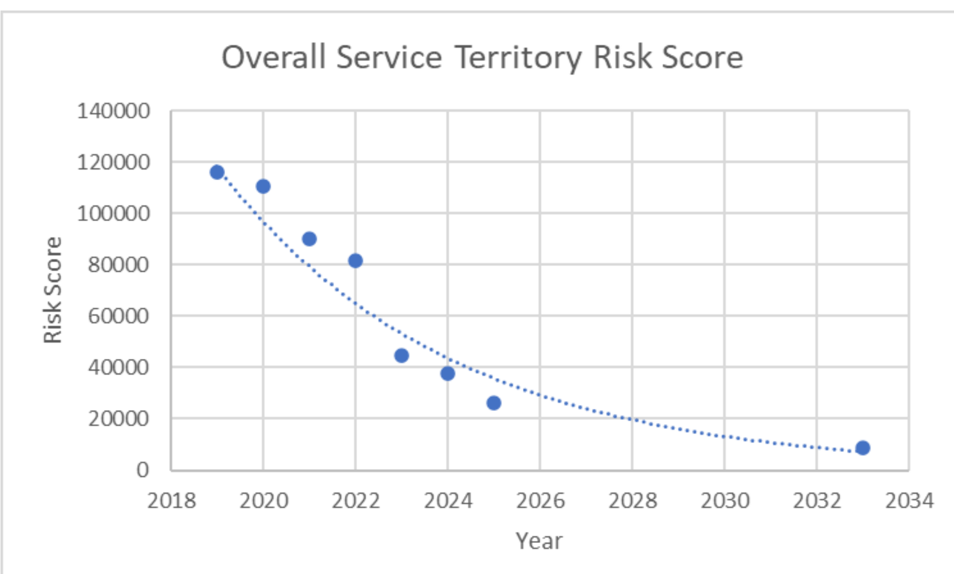


Figure 7-3 Projected Overall Service Territory Risk Graph

Table 7-4 Projected Overall Service Territory Risk

Circuit	Substation	2019 Wildfire Risk Group[1]	2020 Wildfire Risk Group[1]	2021 Wildfire Risk Group[1]	2022 Wildfire Risk Group[1]	2023 Wildfire Risk Group[2]	2024 Wildfire Risk Group[2]	2025 Wildfire Risk Group[2]	2033 Wildfire Risk Group[2]
Radford	SCE Feed	30521	30621	31215	31215	522	522	522	522
Shay	SCE Feed	14230	13367	7103	3524	0	0	0	0
Baldwin	SCE Feed	7185	7763	7606	6891	6891	3197	345	345
Boulder	Village	3351	2951	1230	882	882	882	0	0
North Shore (Fawnskin	Fawnskin	7518	7538	6721	6717	6717	6095	4585	0
Erwin Lake	Maltby	7401	3416	2006	0	0	0	0	0
Pioneer (Palomino)	Palomino	5706	5206	2426	2730	2730	2730	2730	0
Clubview	Moonridge	3460	4060	3331	3225	3011	2203	1193	0
Goldmine	Moonridge	5559	6659	4491	4539	4539	3731	2721	0
Paradise	Maltby	3493	3493	2894	1810	1242	1242	1242	0
Sunset	Maple	3583	3883	2533	2374	2075	2075	259	0
Sunrise (Maple)	Maple	2650	2650	2217	1857	1712	1712	396	0
Holcomb (Bear City)	Bear City	5916	4516	4205	4746	4746	3413	2605	1382
Georgia	Pineknot	1919	2019	1280	1384	1103	1103	1103	847
Eagle	Pineknot	2072	2072	1813	1813	1509	1509	1509	522
Harnish (Village)	Village	385	585	793	786	786	786	786	742
Garstin	Meadow	2440	1750	1392	1366	906	906	906	846
Lagonita	Village	2023	2323	1576	1533	1453	1453	1453	374
Interlaken	Meadow	3275	2475	1652	1485	1117	1117	1117	1009
Castle Glen (Division)	Division	1982	2238	2365	1483	1483	1483	1303	495
Country Club	Division	984	845	709	640	640	640	640	608
Fox Farm	Meadow	0	0	0	0	0	0	0	0
Pump House (Lake)	Lake	287	287	202	202	202	202	202	202
Lift (Summit TOU)	Summit	28	28	627	627	627	627	627	627
Skyline (Summit Res)	Summit	0	0	0	0	0	0	0	0
Geronimo (Bear Mtn.)	Bear Mtn.	0	0	0	0	0	0	0	0
		115969	110745	90386	81829	44891	37626	26243	8520

Wildfire Risk Groups	
High	>3000
Moderate	1201-2999
Low	<1200

7.2.2.2 Risk Impact of Mitigation Initiatives

The electrical corporation must calculate the expected "x% risk impact" of each of its mitigation initiative activity targets for each year from 2023–2025. The expected x% risk impact is the expected percentage risk reduction on the last day of each year compared to the first day of that same year. For example:

For protective devices and sensitivity settings, the risk on Jan. 1, 2024 = 2.59 ×10−1

After meeting its planned initiative activity targets for protective devices and sensitivity settings, the risk on Jan. 1, 2024 = 1.29 ×10−1

The expected x% risk impact for the protective devices and sensitivity settings initiative in 2024 is: risk before−risk after risk before×100 2.59 ×10−1−1.29 ×10−12.59 ×10−1×100=50%

The expected "x% risk impact" numbers must be reported for each planned mitigation initiative activities in the specific mitigation initiative sections of Section 8 (see example tables in Section 8).

BVES calculates the expected risk-impact percentage of each of its mitigation initiative activity targets from 2023-2025 utilizing the following formula:

$$((\text{risk before}-\text{risk after}))/(\text{risk before})\times 100$$

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

The objective of the service territory risk reduction summary is to provide an integrated view of wildfire risk reduction across the electrical corporation's service territory. The electrical corporation must provide the following information:

- *Tabular summary of numeric risk reduction for each high-risk circuit, showing risk levels before and after the implementation of mitigation initiatives. This must include the same circuits, segments, or span IDs presented in Section 6.4.2. The table must include the following information for each circuit:*
    - ***Circuit, Segment, or Span ID**: Unique identifier for the circuit, segment, or span.*
        - *If there are multiple initiatives per ID, each must be listed separately, using an extended to provide a unique identifier*
    - ***Overall Utility Risk**: Numerical value for the overall utility risk before and after each mitigation initiative.*
    - ***Mitigation initiatives by implementation year**: Mitigation initiatives the electrical corporation plans to apply to the circuit in each year of the WMP cycle.*

BVES' service area risk reduction depicted in Figure 7-3 intends to provide an integrated view of wildfire risk reduction across its service territory from 2023-2025.

Table 7-5 Summary of Risk Reduction for Top-Risk Circuits

Circuit ID	Jan 1, 2023 Overall Risk	Jan 1, 2023 – Dec 31, 2023 Mitigation Initiatives	Jan 1, 2024 Overall Risk	Jan 1, 2024 – Dec 31, 2024 Mitigation Initiatives	Jan 1, 2025 Overall Risk	Jan 1, 2025 – Dec 31, 2025 Mitigation Initiatives	Jan 1, 2026 Overall Risk
Radford	31215	Covered Conductor & Fire Resistant Poles	522		522		522
Shay	3524	Covered Conductor & Pole Assessment and Hardening	0		0		0
Baldwin	6891	Covered Conductor & Pole Assessment and Hardening	6891	Covered Conductor & Pole Assessment and Hardening	3197		345
North Shore	6717		6717	Covered Conductor & Pole Assessment	6717	Covered Conductor & Pole Assessment	4585

				and Hardening		and Hardening	
Clubview	3225	Covered Conductor & Pole Assessment and Hardening	3011	Covered Conductor & Pole Assessment and Hardening	2203	Covered Conductor & Pole Assessment and Hardening	1193
Goldmine	4539		4539	Covered Conductor & Pole Assessment and Hardening	3731	Covered Conductor & Pole Assessment and Hardening	2721
Holcomb	4746		4746	Covered Conductor & Pole Assessment and Hardening	3413	Covered Conductor & Pole Assessment and Hardening	2605

7.2.3 Interim Mitigation Strategies

As indicated in Section 7.1.4.3, for each mitigation that will require greater than one year to implement, the electrical corporation must assess the potential need for interim mitigation initiatives to reduce risk until the primary or permanent mitigation initiative is in place. If the electrical corporation determines that an interim mitigation initiative is necessary, it must also develop and implement that initiative as appropriate.

The electrical corporation must provide a description of the following in this section of the WMP:

- *The electrical corporation's procedures for evaluating the need for interim risk reduction*
- *The electrical corporation's procedures for determining which interim mitigation initiative(s) to implement*
- *The electrical corporation's characterization of each interim risk management/reduction action and evaluation of its specific capabilities to reduce risks, including:*
- *Potential consequences of risk event(s) addressed by the improvement/mitigation*
- *Frequency of occurrence of the risk event(s) addressed by the improvement/mitigation*

Each interim mitigation initiative planned by the electrical corporation for implementation on high-risk circuits must be listed as a mitigation initiative in Section 8. In addition, interim mitigation initiatives must be discussed in the relevant mitigation initiative sections of the WMP and included in the related target tables.

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 7.1.4.1 to evaluate the need for interim risk reduction, determining which mitigations to implement, and the characterization of each interim risk reduction action.

8. Wildfire Mitigation

8.1 Grid Design, Operations, and Maintenance

8.1.1 Overview

In this section, the electrical corporation must identify objectives for the next 3- and 10-year periods, targets, and performance metrics related to the following grid design, operations, and maintenance programmatic areas:

- *Grid design and system hardening*
- *Asset inspections*
- *Equipment maintenance and repair*
- *Asset management and inspection enterprise system(s)*
- *Quality assurance / quality control*
- *Open work orders*
- *Grid operations and procedures*
- *Workforce planning*

8.1.1.1 Objectives

Each electrical corporation must summarize the objectives for its 3-year and 10-year plans for implementing and improving its grid design, operations, and maintenance. These summaries must include the following:

- *Identification of which initiative(s) in the WMP the electrical corporation is implementing to achieve the stated objective, including Utility Initiative Tracking IDs*
- *Reference(s) to applicable codes, standards, and best practices/guidelines and an indication of whether the electrical corporation exceeds an applicable code, standard, or regulation*
- *Method of verifying achievement of each objective*
- *A target completion date*
- *Reference(s) to the WMP section(s) or appendix, including page numbers, where the details of the objective(s) are documented and substantiated*

This information must be provided in Table 8-1 for the 3-year plan and Table 8-2 for the 10-year plan. Examples of the minimum acceptable level of information are provided below.

Table 8-1 Grid Design, Operations, and Maintenance Objectives (3-year plan)

Objectives for Three Years	Applicable Initiative(s), Tracking ID(s)	Applicable Regulations, Codes, Standards, and Best Practices (See Notes)	Method of Verification (i.e., program)	Completion Date	Reference (Section and Page Number)

Replace all sub-transmission (34.5 kV) overhead bare conductors with covered conductors	Covered Conductor Replacement Project, covered conductor installation GD_1 Radford Line Replacement Project, Covered conductor installation GD_2			31-Dec-25	
Assess and remediate all sub-transmission (34 kV) poles	Covered Conductor Replacement Project, covered conductor installation GD_3 Radford Line Replacement Project, Covered conductor installation GD_4			31-Dec-25	
Harden secondary evacuation routes in highest risk areas	Evacuation Route Hardening Project, Distribution pole replacements and reinforcements, GD_6			31-Dec-25	
Remove all tree attachments from high-risk areas	Tree Attachment Removal Project, Other grid topology improvements to minimize risk of ignitions, GD_19			31-Dec-25	

On a priority basis, automate substations, switches, field devices, and fuse tripsavers and connect to SCADA	Substation Automation, Installation of system automation equipment, GD_12 Switch and Field Device Automation, Installation of system automation equipment, GD_13 Fuse TripSaver Automation, Installation of system automation equipment, GD_15			31-Dec-25	
Replace Capacitor Banks and Connect to SCADA	Capacitor Bank Upgrade Project, Installation of system automation equipment, GD_14			31-Dec-25	
Pursue development and execution of the Bear Valley Solar Energy Project	Bear Valley Solar Energy Project, Microgrids, GD_10			31-Dec-24	
Pursue development and execution of the Energy Storage Project	Energy Storage Project, Microgrids, GD_11			31-Dec-24	

Upgrade highest risk substations	Partial Safety and Technical Upgrades to Maltby Substation, Other technologies and systems not listed above, GD_22 Safety and Technical Upgrades to Lake, Other technologies and systems not listed above, GD_23 Substation Partial Safety and Technical Upgrades to Village Substation, Other technologies and systems not listed above, GD_24			31-Dec-25	
Continue robust asset inspection routine of annual Detailed Inspections, Patrol Inspections, LiDAR surveys, UAV HD Photography & Thermography, 3rd party Ground Patrols, Intrusive Pole Testing, and Substation Inspections	Asset inspections, GD-25, GD_26, GD_27, GD_28, GD_29, GD_30, GD_31, GD_32			31-Dec-25	

Implement robust asset management and inspection enterprise system.	Asset management and inspection enterprise system(s), GD_34			31-Dec-23	
Improve quality assurance and quality control program on asset work and asset inspection.	Quality assurance / quality control, GD-35			31-Dec-23	

Note: An asterisk indicates that the electrical corporation exceeds a particular code, regulation, standard, or best practice. The electrical corporation must provide a reference to the appendix section and page providing further documentation, justification, and substantiation.

Table 8-2 Grid Design, Operations, and Maintenance Objectives (10-year plan)

Objectives for 10 Years (2026 -2032)	Applicable Initiative(s), Tracking ID(s)	Applicable Regulations, Codes, Standards, and Best Practices (See Notes)	Method of Verification (i.e., program)	Completion Date	Reference (Section and Page Number)
Replace all high and medium risk distribution (4 kV) overhead bare conductors with covered conductors	Covered Conductor Replacement Project, Covered conductor installation GD_1			31-Dec-32	Section 8.1.2.1
Assess and remediate all high and medium risk distribution (4 kV) poles	Covered Conductor Replacement Project, Covered conductor installation GD_3				Section 8.1.2.3
Harden secondary evacuation routes	Evacuation Route Hardening Project, Distribution pole				Section 8.1.2.3

	replacements and reinforcements , GD_6				
Remove all tree attachments from distribution system	Tree Attachment Removal Project, Other grid topology improvements to minimize risk of ignitions, GD_19				Section 8.1.2.X
Automate remaining substations, switches, field devices, and fuse tripsavers and connect to SCADA	Substation Automation, Installation of system automation equipment, GD_12 Switch and Field Device Automation, Installation of system automation equipment, GD_13 Fuse TripSaver Automation, Installation of system automation equipment, GD_15				Section 8.1.2.X
Replace remaining Capacitor Banks and Connect to SCADA	Capacitor Bank Upgrade Project, Installation of system automation equipment, GD_14				Section 8.1.2.X
Pursue other renewable generating facility opportunities	Microgrids				Section 8.1.2.X

Pursue other energy storage project opportunities	Microgrids				Section 8.1.2.X
Assess emerging technologies aimed at early detection of asset degradation, wire down detection, and other ignition prevention/mitigation technologies	Emerging grid hardening technology installations and pilots, GD_9				Section 8.1.2.X
Assess other emerging sub-transmisison and distribution inspection techniques	Asset inspections				Section 8.1.2.X

Note: An asterisk indicates that the electrical corporation exceeds a particular code, regulation, standard, or best practice. The electrical corporation must provide a reference to the appendix section and page providing further documentation, justification, and substantiation.

8.1.1.2 Targets

Initiative targets are forward-looking quantifiable measurements of activities identified by each electrical corporation in its WMP. Electrical corporations will show progress towards completing targets in subsequent reports, including QDRs and WMP Updates.

The electrical corporation must list all targets it will use to track progress on its grid design, operations, and maintenance for three years of the Base WMP. Energy Safety's Compliance Assurance Division and third parties must be able to track and audit each target. For each initiative target, the electrical corporation must provide the following:

- *Utility Initiative Tracking IDs*
- *Projected targets for the three years of the Base WMP and relevant units*
- *Quarterly, rolling targets for end of 2023 and 2024 (inspections only)*
- *For 2023–2025, the "x% risk impact." The x% risk impact is the percentage risk reduction identified in Table 7-2 for a specific mitigation initiative (see Section 7.2.2.1 for calculation instructions)*
- *Method of verifying target completion*

The electrical corporation's targets must provide enough detail to effectively inform efforts to improve the performance of the electrical corporation's grid design, operations, and maintenance initiatives.

Table 8-3 Grid Design, Operations, and Maintenance Targets by Year

Initiative Activity	Tracking ID	Units	2023 Target	x% Risk Impact 2023	2024 Target &	x% Risk Impact 2024	202 Targ

Covered conductor installation	GD_1		Circuit Miles of Line Replaced		12.9		12.9
Covered conductor installation	GD_2		Circuit Miles of Line Replaced	2.7	0		0
Undergrounding of electric lines and/or equipment	GD_3		Initiate Underground Projects as needed (% of Budget)	100%	100%		100%
Distribution pole replacements and reinforcements	GD_4		Number of Poles Replaced	200	200		200
Distribution pole replacements and reinforcements	GD_5		Number of Poles Replaced	70	0		0
Distribution pole replacements and reinforcements	GD_6		Number of Poles that had Wire Mesh Installed on them.	500	500		500
Transmission pole/tower replacements and reinforcements	GD_7		N/A				
Traditional overhead hardening	GD_8		As Needed Maintenance (% of Budget)	100%	100%		100%
Emerging grid hardening technology installations and pilots	GD_9		N/A				

Microgrids	GD_10		Preform Necessary Project Action	No Action	File Application		No Ac
Microgrids	GD_11		Preform Necessary Project Action	No Action	File Application & Obtain Permit		No Ac
Installation of system automation equipment	GD_12		Number of Substations Automated and Connected to SCADA	3	3		3
Installation of system automation equipment	GD_13		Number of Field Switches Automated and Connected to SCADA	13	10		11
Installation of system automation equipment	GD_14		Number of Capacitor Banks Replaced and Connected to SCADA	6	6		6
Installation of system automation equipment	GD_15		Number of Fuse TripSavers Automated and Connected to SCADA	10	50		50
Installation of system automation equipment	GD_16		Project Milestones for Server Installation	32%	64%		100% Projec Comp

Installation of system automation equipment	GD_17		Project Milestones for Distribution Management Center	No Action	50% Project Completion		100% Projec Comp
Line removals (in HFTD)	GD_18		N/A				
Other grid topology improvements to minimize risk of ignitions	GD_19		Number of Tree Attachments Removed	100	100		100
Other grid topology improvements to mitigate or reduce PSPS events	GD_20		N/A				
Other technologies and systems not listed above	GD_21		Project Milestones for Propane Engine Upgrades	32%	64%		100% Projec Comp
Other technologies and systems not listed above	GD_22		Project Milestones for Maltby Substation	32%	64%		100% Projec Comp
Other technologies and systems not listed above	GD_23		Project Milestones for Lake Substation	32%	64%		100% Projec Comp
Other technologies and systems not listed above	GD_24		Project Milestones for Village Substation	32%	64%		100% Projec Comp
Equipment maintenance and repair	GD_33		As Needed Maintenance (% of Budget)	100%	100%		100%

Asset management and inspection enterprise system(s)	GD_34		Maintenance of Asset Management System	100%	100%		100%
Quality assurance / quality control	GD_35		Number of Asset QCs on WMP Work	20	20		20
Open work orders	GD_36		No descrep exceeding GO95 resolution timeframes	All WO resolved within GO 95 Timeframe	All WO resolved within GO 95 Timeframe		All WC resolv within 95 Timefr
Equipment Settings to Reduce Wildfire Risk	GD_37		Review and Evaluate System Settings	Review and Evaluate System Settings	Review and Evaluate System Settings		Reviev and Evalua Syster Setting
Grid Response Procedures and Notifications	GD_38		Review and Update Procedure Annually	Finalize Review	Finalize Review		Finaliz Reviev
Personnel Work Procedures and Training in Conditions of Elevated Fire Risk	GD_39		Review and Update Procedure Annually. Verification of Training Annual	Finalize Review	Finalize Review		Finaliz Reviev
Workforce Planning	GD_40		Verify Appropriate Staffing Levels for Wildfire Related Activities	Staffing Level Verified	Staffing Level Verified		Staffin Level Verifie

Table 8-4 Asset Inspections Targets by Year

Initiative Activity	Tracking ID	Units	Target End of Q2 2023	Target End of Q3 2023	End of Year Target 2023	X% Risk Impact 2023	Target End of Q2 2024	Target End of Q3 2024	End of Year Target 2024	X% Risk Impact 2024	Target 2025	X% Risk Impact 2025	Method of Verification
Asset inspections	GD_25	Circuit Miles Inspected	60	100	134		0	40	51		53		Quantitative
Asset inspections	GD_26	Circuit Miles Inspected	0	211	211		0	211	211		211		Quantitative
Asset inspections	GD_27	Circuit Miles Inspected	0	211	211		0	211	211		211		Quantitative
Asset inspections	GD_28	Circuit Miles Inspected	0	211	211		0	211	211		211		Quantitative
Asset inspections	GD_29	Circuit Miles Inspected	0	211	211		0	211	211		211		Quantitative
Asset inspections	GD_30	Circuit Miles Inspected	0	211	211		0	211	211		211		Quantitative
Asset inspections	GD_31	Number of Poles Intrusively Inspected	0	300	850		0	300	850		850		Quantitative
Asset inspections	GD_32	Number of Substations Inspected	72	108	144		72	108	144		144		Quantitative

8.1.1.3 Performance Metrics Identified by the Electrical Corporation

Performance metrics indicate the extent to which an electrical corporation's Wildfire Mitigation Plan is driving performance outcomes. The electrical corporation must:

- *List the performance metrics the electrical corporation uses to evaluate the effectiveness of its grid design, operations, and maintenance in reducing wildfire and PSPS risk*

For each of these performance metrics listed, the electrical corporation must:

- *Report the electrical corporation's performance since 2020 (if previously collected)*
- *Project performance for 2023-2025*
- *List method of verification*

The electrical corporation must ensure that each metric's name and values are the same in its WMP reporting as its QDR reporting (specifically, QDR Table 2 and QDR Table 3). Metrics listed in this section that are the same as performance metrics required by Energy Safety and reported in QDR Table 2 (Performance Metrics)25 must match those reported in QDR Table 2. Metrics listed in this section that are not the same as any of the performance metrics identified by Energy Safety and reported in QDR Table 2 must match those reported in QDR Table 3.

The electrical corporation must:

- *Summarize its self-identified performance metrics in tabular form*
- *Provide a brief narrative that explains trends in the metrics*

Table 8-5 Grid Design, Operations, and Maintenance Performance Metrics Results by Year

Performance Metrics	2020	2021	2022	2023 Projected	2024 Projected	2025 Projected	Method of Verification (e.g., third party evaluation, QDR)
Equipment-caused ignitions	0	0	0	0	0	0	QDR
Equipment caused outages	61	51	75	62	62	62	QDR
Grid inspection findings	733	151	356	415	415	415	QDR
Open work orders (tags)							

8.1.2 Grid Design and System Hardening

In this section the electrical corporation must discuss how it is designing its system to reduce ignition risk and what it is doing to strengthen its distribution, transmission, and substation infrastructure to reduce the risk of utility-related ignitions resulting in catastrophic wildfires.

The electrical corporation is required, at a minimum, to discuss grid design and system hardening for each of the following mitigation activities:

1. *Covered conductor installation*
2. *Undergrounding of electric lines and/or equipment*
3. *Distribution pole replacements and reinforcements*
4. *Transmission pole/tower replacements and reinforcements*
5. *Traditional overhead hardening*
6. *Emerging grid hardening technology installations and pilots*
7. *Microgrids*
8. *Installation of system automation equipment*
9. *Line removal (in the HFTD)*
10. *Other grid topology improvements to minimize risk of ignitions*
11. *Other grid topology improvements to mitigate or reduce PSPS events*
12. *Other technologies and systems not listed above*

In Sections 8.1.2.1 through 8.1.2.12, the electrical corporation must provide a narrative including the following information for each grid design and system hardening mitigation activity:

- ***Utility Initiative Tracking ID.***
- ***Overview of the activity**: A brief description of the activity including reference to related objectives and targets. Additionally, the overview must identify whether the activity is a program, project, pilot, or study.*
- ***Impact of the activity on wildfire risk.***
- ***Impact of the activity on PSPS risk.***
- ***Updates to the activity**: Changes to the initiative since the last WMP submission and a brief explanation as to why those change were made. Discuss any planned improvements or updates to the activity and the timeline for implementation.*

8.1.2.1 Covered conductor installation (Tracking ID: GD_1 &GD_2)

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 impacts on reliability. Covered wire is an accepted practice to eliminate tree and vegetation and debris contact to reduce wildfire ignitions. 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. The replacement program is prioritized based on higher-risk circuits to maximize the risk reduction.

Impact of the Activity on Wildfire Risk

This initiative intends to reduce potential ignition events by installing wire with insulated protective covers. It also addresses the replacement of 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).

The Covered Wire Program replaces 34.5 kV bare wire at a rate of 4.3 circuit miles per year and to replace 4 kV bare wire at a rate of 8.6 circuit miles per year. Additionally, the Radford Line Replacement Project is addressed under this subsection.

<u>Covered Wire Program – 34.5 kV System</u>

BVES intends to install covered wire on all sub-transmission lines (34.5 kV). This will result in the entire overhead 34.5 kV system in the HFTD being either underground or covered. This program will reduce the risk of sub-transmission lines contacting vegetation or other debris and causing an ignition to near zero.

BVES plans to replace all overhead sub-transmission bare wire with covered wire over a 6-year period of execution from 2020 to 2026 covering approximately 4.3 miles per year.

<u>Covered Wire Program – 4 kV System</u>

BVES intends to replace all bare 4 kV distribution wire in identified high-risk areas within the HFTD with covered wire. This will result in approximately 86 miles of the 4 kV distribution lines in the system in the HFTD being covered at approximately 8.6 miles per year for the next 10 years. Based upon this schedule, 4kV wire in high-risk areas will be replaced by 2032. The remaining 4 kV lines will take another 10 years. This program will significantly reduce the risk of distribution lines contacting vegetation or other debris and causing an ignition. The high-risk areas are primarily defined by high vegetation density.

Based on benchmarking with other utilities’ estimated effectiveness against ignition risks, discussions with its covered conductor suppliers, and the short amount of time that it has installed covered conductor, BVES believes that the estimate of effectiveness on ignition risk drivers in its service territory is approximately 90%. For comparison, the SCE estimated full deployment of covered conductor in high-risk areas to mitigate approximately 60 percent of fires associated with electrical distribution facilities in defined risk tiers. BVES believes SCE’s effectiveness results are a valid, relative measure of effectiveness of this technology, with underground conversion providing the baseline (100 percent) for purposes of our comparison.

Covered Conductor Project – Radford Line Sub-transmission Project

This project includes two components: (1) replacement of the bare wire with covered conductor and (2) replacement of the wood poles with fire resistant poles. The bare wire replacement portion of the project is discussed and tracked in this initiative. The pole replacement portion of the project is discussed and tracked under initiative Section 8.1.2.3 (Distribution pole replacement and reinforcement, including with composite poles).

BVES is replacing bare wire with covered conductor on the Radford 34.5 kV line. BVES chose to cover this line specifically, which resides in the HFTD Tier 3 area, since it has the highest wildfire risk of all of BVES's overhead facilities. The line is in a densely vegetated area that is difficult to patrol, due to no road access. The project also includes replacing the aged wood poles with fire resistant poles. Replacing the bare wire with covered wire will provide a high level of effectiveness for preventing a potential ignition leading to a wildfire. Utilizing fire resistant poles will improve resiliency to quickly restore power to Big Bear Lake in the event the area suffers a major wildfire. All bare wire in The HFTD Tier 3 is to be covered by end of calendar year 2023 if permitting issues with the USFS are resolved in time to complete construction prior to the winter of 2023.

Impact of the Activity on PSPS Risk

The expanded use of covered conductor will reduce BVES's likelihood of implementing a PSPS because it reduces the risk of vegetation or debris contacting a bare live wire which can cause an ignition. Additionally, once the Radford line has covered conductor installed that line will no longer be de—energized during fire season and can limit the impact of a SCE-activated PSPS of BVES's supply lines.

Updates to the Activity

BVES will apply any lessons learned throughout the progression of the program, collecting information on supply logistics, pole replacements necessary to support covered wire installation, and covered wire installation work techniques and rates in order to optimize the program execution. As part of the project, BVES will install utility fiber cable and will use this for future system monitoring efforts (cameras, infrared sensors, system diagnostics sensors, etc.) and for fast acting switches on the circuit.

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

34.5kV System

BVES will continue covered conductor installations on high-risk areas towards a program goal of 100 percent completion by end of calendar year 2026.

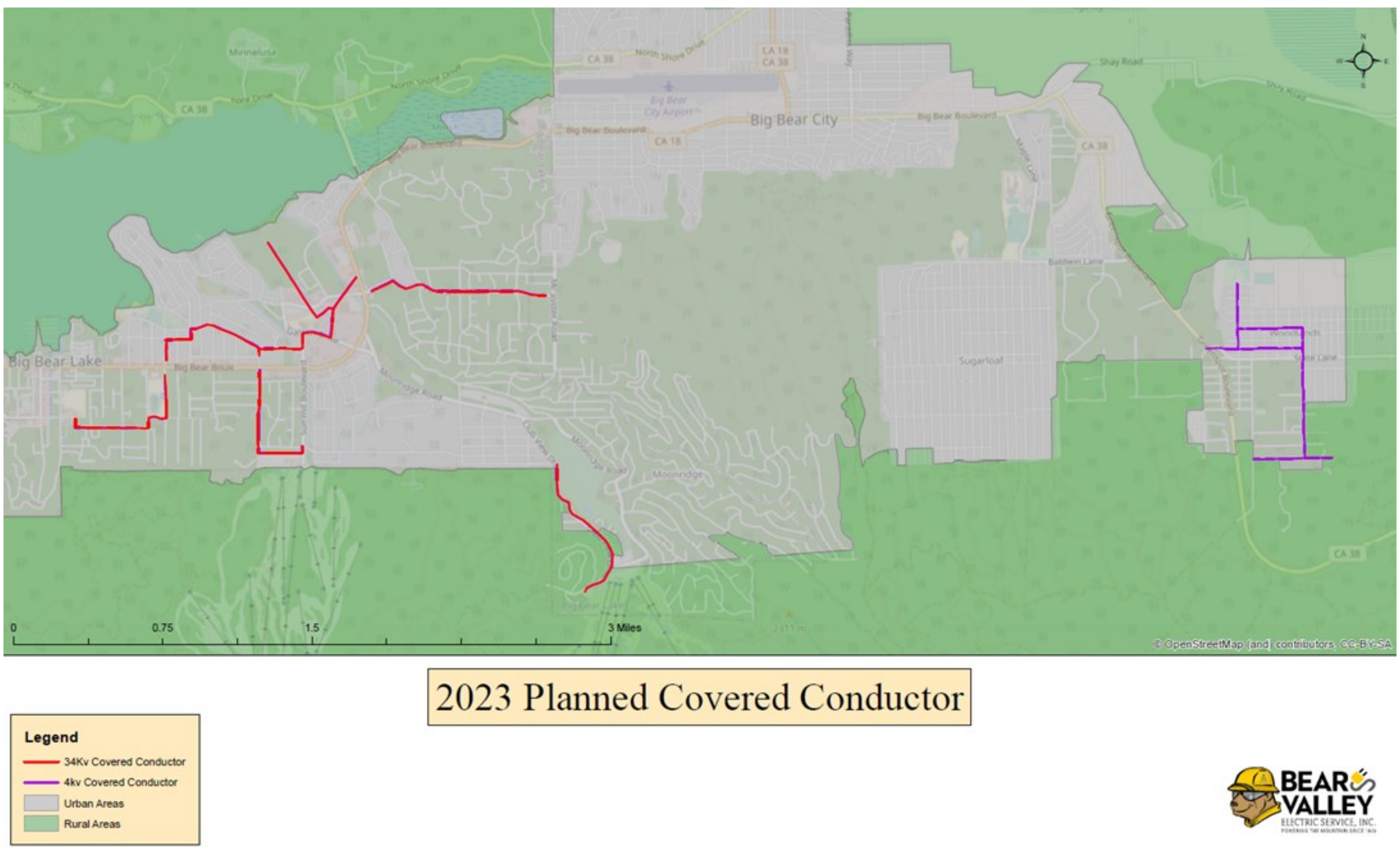
4kV System

BVES will continue replacing 4 kV bare wire in high-risk areas towards a program goal of 100 percent completion (for high-risk areas) by end of calendar year 2032. BVES will then continue to replace 4 kV bare wire until it no longer has bare wire in its 4kV system.

Radford Line

BVES was delayed in 2022 from installing covered conductor on the Radford line due to permitting delays with the US Forest Service (USFS). BVES is now meeting with USFS regularly and expects to receive the permit and complete the work by November 2023.

Figure 8-1 2023 Planned Covered Conductor Installation Location



8.1.2.2 Undergrounding of electric lines and/or equipment (Tracking ID: GD_3)

Overview

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. Converting circuits from overhead to underground nearly eliminates the risk of ignition and exists minimally surrounding the area where equipment resurfaces.

BVES does not have any major UG projects planned at this time. 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 alternative is to convert to bare conductor overhead facilities to covered conductor overhead 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 significantly.

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 extreme or elevated risk so any UG has a significant wildfire risk benefit.

Impact of the Activity on PSPS Risk

The minimal amount of UG projects described above are not expected to have any impact on BVES's likelihood to activate a PSPS.

Updates to the Activity

There are no immediate plans for large-scale undergrounding projects in 2023. BVES will continue to conduct small UG projects driven by new developments and local government in 2023.

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 minimum specifications.

8.1.2.3 Distribution Pole Replacements and Reinforcements (Tracking ID: GD_4 – GD_5, GD_6)

Overview

This initiative covers costs associated with four separate programs and projects, which includes Distribution Pole Replacement and reinforcement, covered conductor Radford line project, and the evacuation route hardening program.

Distribution Pole Replacement and Reinforcement – GO 95 Projects (Tracking ID: GD6)

Pole loading infrastructure hardening and replacement program based on pole loading assessment program (Tracking ID: XXXXX)

Overview

In compliance with GOs 95 and 165, BVES has an ongoing program to assess and remediate noncompliant distribution poles. 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 will be 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.

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 a HFTD Tiers 2 and 3, any pole failure is considered a high fire risk. Additionally, BVES is above 3000 ft sea level and is subject to heavy loading requirements. Overhead distribution lines are exposed to severe weather including heavy snow, ice, and high winds.

To promote efficiency and minimize duplication of work, and subject to the remediation time frames in GO 95, the rate of testing and resulting remediation designs may be integrated with other potential work proposed in the same area which is also more operationally efficient and cost effective. In addition, the program may require a sufficient number of pole replacements on a line or in a concentrated area that it is prudent to undertake a more comprehensive replacement design, as opposed to mere replacement of individual poles. The remediation work is performed by BVES or contractor resources based on available capacity, cost, and other related factors.

Impact of the Activity on PSPS Risk

This activity will lower the low risk of PSPS activation on BVES's system. Pole failures are a concern for igniting fires and having a new pole or reinforced pole reduces that likelihood. BVES considered pole failure as part of its determination for its PSPS activation thresholds.

Updates to the Activity

This activity is mostly achieved in conjunction with the covered conductor program. Before covered conductor is installed, each affected pole is fully assessed and those not meeting GO-95 requirements are replaced or remediated.

<u>Covered Conductor Project – Radford Line Sub-transmission Project (Tracking ID: XXX)</u>

Overview

This initiative intends to reduce the potential of one of the main power supply lines to Big Bear Lake from being lost, should the area suffer a wildfire or other event. Additionally, the initiative removes the likelihood BVES would need to initiate a PSPS on this circuit during extreme fire weather conditions.

BVES is replacing 70 aged wood poles on the Radford 34.5 kV line with fire resistant poles that will improve resiliency to quickly restore power to Big Bear Lake in the event the area suffers a major wildfire.

Impact of the Activity on Wildfire Risk

BVES chose to cover this line located in the HFTD Tier 3 area and replace the poles with fire resistant poles specifically because it has the highest wildfire risk of all of BVES's overhead facilities. The line is in a densely vegetated area that is difficult to patrol, due to no road access.

Impact on PSPS Risk

Replacing the poles will improve system resiliency from wildfires and reduce the likelihood that BVES would need to declare a PSPS on this line.

Evacuation Route Hardening Pilot & Program (Tracking ID:XXXX)

Overview

BVES's service area has three predetermined evacuation routes, developed by the local sheriff department and other government officials, to evacuate the public in the event of an emergency, including a wildfire. The 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. The evacuation hardening pilot project performed in 2020 and completed in 2021 was designed to determine availability, cost effectiveness, and ability to install technology such as fire-resistant pole wrap, steel poles, concrete poles, ductile iron poles, and fire-resistant fiberglass poles. These proposed measures are intended to increase resiliency to demonstrate the ability to keep evaluation routes safe from failed BVES electrical assets during a wildfire. BVES is now focusing on secondary evacuation routes that lead to the primary routes by installing the wire wrap mesh on approximately 500 poles per year.

Impact of the Activity on Wildfire Risk

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. 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. BVES hardened the three main evacuation routes (800 poles) over two years with wire wrap program. In addition, BVES will implement the following policy that requires when wood poles are to be replaced for any reason on main evacuation routes, that they are to be replaced with fire resistant composite or other acceptable pole types (LWS or ductile iron after testing). If undergrounding opportunities arise along evacuation routes, evaluations will be performed to determine the suitability of undergrounding.

Impact of the Activity on PSPS Risk

Since the primary objective on this evacuation route hardening is to add resiliency and safety of the evacuation routes the program does not directly address the impact to PSPS Risk but reduces the chances of a wildfire risk and therefore inherently provides for a reduction on the chances of declaring a PSPS.

Updates to the Activity

BVES will continue its effort across its service territory to upgrade and replace poles and already achieved hardening with a significant portion of its poles in service 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.

8.1.2.4 Transmission Pole/Tower Replacements and Reinforcements (Tracking ID: GD_7)

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

8.1.2.5 Traditional Overhead Hardening (Tracking ID: GD_8)

Maintenance, repair, and replacement of distribution and sub-transmission components and equipment

Overview

This initiative includes the 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. Work in this initiative is performed in accordance with GO 95 standards. Maintaining and replacing degraded equipment will reduce the risk of equipment failure and subsequent ignition risk.

BVES maintains its electrical system in accordance with applicable GOs and industry standards. Costs for new equipment and components installed during pole replacements are captured in CAPEX for that specific pole replacement project while repairs and general maintenance is captured as O&M costs. Distribution and sub-transmission equipment are inspected as follows:

- Detailed asset inspections
- Patrol asset inspection
- LiDAR asset inspection
- UAV Thermography asset inspection
- UAV Photography/Videography asset inspection
- 3rd Party Ground Patrol asset inspection

Equipment issues identified in the inspections are documented and corrected in accordance with GO 95 Rule 18 prioritization. There are no alternatives to maintaining BVES's electrical system to report.

Impact of the Activity on Wildfire Risk

BVES has begun utilizing composite cross arms as an improved material in terms of strength, durability, and less susceptible to fire damage, in its construction and replacement practices and will continue to make further improvements. By addressing equipment issues early through maintenance and inspection programs, the risk of the equipment failing and causing an ignition is reduced.

Impact of the Activity on PSPS Risk

The improved material makes the new crossarms more resilient and the reduces susceptibility to wildfire greatly reduces that risk of a PSPS. Well maintained equipment is less likely to cause ignitions and, therefore, the need to invoke a PSPS is reduced.

Updates to the Activity

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

8.1.2.6 Emerging Grid Hardening Technology Installations and Pilots (Tracking ID: GD_9)

BVES does not have any pilots planned at this time and will continue to monitor developments underway at other utilities.

8.1.2.7 Microgrids (Tracking ID: GD_10, GD_11)

<u>Bear Valley Energy Storage Facility</u>

Overview

BVES proposed the construction of an energy storage project of approximately 5 MW/20 MWh (four-hour) Lithium-Ion NMC utility-grade battery in the BVES service area. This project will complement the Bear Valley Solar Energy Project (BVSEP), 5 MW alternating current single-axis tracker solar generation facility, to be constructed on the same location as the storage facility project and directly feeding the distribution system benefiting all customers.

Impact of the Activity on wildfire Risk

This project aims to reduce activity on PSPS risk but does not significantly reduce the potential to wildfire risk.

Impact of the Activity on PSPS Risk

One of the purposes 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 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.

Updates to the Activity

Once built, these projects will allow BVES to internally supply energy to most of its customers by utilizing its existing peaking power plant (8.4 MW), along with the BVSEP and the energy storage battery to minimize the effects of any PSPS event.

<u>Energy storage/solar energy project</u>

Overview

BVES proposed an Energy Storage and Solar Generating Facility Project that are designed to reduce the likelihood and consequences of disruptive events, including PSPS actions, and provide many of the benefits outlined the Grid Resilience and Innovation Partnerships (GRIP) program.

Bear Valley's service area includes a wilderness environment with heavily-forested treed terrain making the territory vulnerable to potential ignition risk. BVES proposes to construct an energy storage project of approximately 5 MW/20 MWh (four-hour) Lithium-Ion NMC utility-grade battery located in the BVES maintenance yard. This project will complement the Bear Valley Solar Energy Project (BVSEP), 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.

Impact of the Activity on wildfire Risk

The proposed projects enhance safety, reliability, and quality of service. The projects are designed to significantly mitigate the potential of ignitions by removing the need to expand sub-transmission supply lines to Bear Valley's service area, which may cause wildfires with catastrophic loss of life and enormous loss of property.

Impact of the Activity on PSPS Risk

These projects significantly reduce the need for PSPS and the impact of Southern California Edison (SCE) initiating a PSPS event affecting the supply 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.

Updates to the Activity

These projects will be submitted to the CPUC and the County of San Bernardino in 2023. If these proposed projects are approved, BVES will be able to internally supply energy to most of its customers by utilizing its existing peaking power plant (8.4 MW), along with the BVSEP and the energy storage battery to minimize the effects of any PSPS event.

8.1.2.8 Installation of System Automation Equipment (Tracking ID: GD_12 – GD_17)

Overview

<u>Installation of system automation equipment</u>

This initiative covers the various system automation programs implemented to reduce wildfire and PSPS risks. They encompass automation on the grid by installing advanced equipment, upgraded communication infrastructure and data driven upgrades that assist with the automation.

<u>Grid Automation Program (SCADA)</u>

Overview

BVES's current SCADA system is inadequate with few controls for the distribution system and limited monitoring capability. Through the Grid Automation Project, BVES will establish a service area network, build out its SCADA software and historian capabilities, connect/automate substations and field switches, and install circuit metering and monitoring devices such as weather stations. This initiative will also include installation of electric equipment to increase the ability to automate the system with operational controls and monitoring. To further enhance its situational monitoring, BVES outlined a number of initiatives that contribute to its information base and facilitate sharing. These initiative resources include web-based weather resources, BVES-owned weather stations, weather forecasting, and GIS-supported applications, such as its Outage Management System (OMS).

BVES plans to continue to automate its system including the installation of a fiber optic network throughout the service area, automating substations and key field switches, and adding sensors to provide critical system information. Grid automation will enhance operational efficiency, safety, reliability, and wildfire prevention by allowing remote monitoring and real-time fault detection. The fiber optic network is also an enabler for future advanced technologies that reduce wildfire ignition risk.

Impact of the Activity on Wildfire Risk

This initiative is aimed at reducing the risk of ignitions due to faults by enhancing situational awareness and control of the electric distribution system, rapidly detecting fault conditions, localizing faults, and isolating faults from the system. With the implementation of the SCADA network as part of the Grid Automation Program, BVES will enhance its grid as well as conditional awareness into asset performance and potential incidents. This will provide the utility rapid results, instantaneous reads and communications from system enhancements, and optimize system maintenance and remediation deployments with more precision in system management.

Impact of the Activity on PSPS Risk

The enhanced situational awareness and detection of fault conditions allows for an intelligent isolation of faults reducing the risk of PSPS.

Updates to the Activity

The following list demonstrates the current assets monitored and/or controlled via BVES's SCADA system.

Asset
All Bear Valley Power Plant (BVPP) Controls
7.4 kV7 4 kV Circuit Breakers for each of the BVPP generators at the BVPP
4 - 34 kV Ring Bus Circuit Breakers (# 22, 44, 66 & 88) at Meadow Substation
9 Fault Localization Isolation System Restoration 34 kV IntelliRupter Switches (Baldwin IR3430, Shay IR3440, PS3435IR, PS3454IR, PS3436IR, PS3428IR, PS3414IR, PS3415IR & PS3456IR)
Shay 34 kV Auto Recloser (IR3440)
Baldwin 34 kV Auto Recloser (IR3430)
Radford 34 kV Auto Recloser (IR3470)
Palomino Substation

Moonridge Substation
Pineknot Substation

In 2022, BVES connected three substations to the SCADA network. In 2023-2025 WMP, the Substation Automation Project will be implemented, which will connect three substations per year to the SCADA network. The following items will also be connected in 2023.

Asset
6 Capacitor Banks – 6 locations: 2 on the Boulder Circuit, 2 on the Erwin Circuit, 1 on the North Shore Circuit and 1 on the Paradise Circuit
8 - 34 kV Field Switches
4 - 4kV Field Switches at 4 tie switch locations
Trip Savers at 4 locations (Radio Study)
Fault Indicators (FI) – proposed to install 79 FI's, Radio Study will be part of the trip saver radio study. (7 locations on 34kV for SCADA connection) All Bear Valley Power Plant (BVPP) Controls

BVES will leverage the network connectivity capabilities gained by the project to eventually deploy an array of field devices that enhance situational awareness and detect and remedy system faults and potential ignition events. BVES will apply any lessons learned throughout the progression of the program.

Substation Automation Project

Overview

The project aims to connect nine substations, three per year in 2023-2025, to Bear Valley's SCADA network in order to 13 allow remote real-time monitoring, reporting, and documenting key substation parameters over three years. 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 distribution system to fully enable monitoring and control of critical equipment at the substations throughout the distribution system. Critical switches at substations will be automated and connected to SCADA in a phased approach. Connectivity to SCADA will be via the BVES service area fiber optic network. Additionally, sensors will be placed throughout the substations to continuously monitor volt-ampere reactive (VAR) performance and power quality. Bear Valley connected the Palomino, Moonridge, and Pineknot Substations to SCADA by the end of 2022.

Impact of the Activity on Wildfire Risk

System will monitor, report via alarms, and document key parameters that may indicate impending catastrophic equipment failures that may cause ignitions leading to wildfires and/or large oil spills that may damage the environment allowing Bear Valley allowing immediate action to be taken by Bear Valley crews and first responders. Additionally, this project will allow Bear Valley to remotely and rapidly de-energize a circuit when the circuit is determined to be at high risk of causing an ignition which may result in a wildfire and rapidly assess the boundaries of potential faults that caused the outage, allowing fault location precision that crews can act on.

Rapid fault localization may reduce the risk of ignitions resulting from wildfires and clearly has an impact on reducing time to restore from outages. Finally, the project provides risk reduction regarding downed wires and sustained outages.

Impact of the Activity on PSPS Risk

This project would allow for quick and efficient remote switching operations at the circuit level minimizing the impact to customers significantly reducing outage time for customers by enabling quick restoration of unaffected portions of the distribution system when the fault is localized during faulted, storm, and/or other disaster conditions. Additionally, the project will incorporate available and future distributed generation sources within grid resilience planning and Improve response to outages through input on substation device status into the Outage Management System (OMS).

Updates to the Activity

In 2023, Bear Valley plans to connect and automate Village, Meado, and Bear Mountain substations. Bear City, Division, and Fawnskin are planned for upgrades in 2024, and Maltby, Maple, and Lake substations are planned for connection and automation in 2025. The Snow Summit substation will be upgraded through an Added Facilities agreement with Snow Summit in either 2023 or 2024. This means that all of BVES's substations will be connected to SCADA and fully automated by 2025.

Fault Isolation Localization and Service Restoration (FLISR)

Overview

The Fault Localization Isolation and System Restoration (FLISR) installs nine smart high voltage switches and integrates three existing auto-reclosers and one auto-transfer switch on the 34.5 kV system. The system leverages the network installed by the Grid Automation Project to rapidly detect and isolate faults and restore unaffected portions of the system to the maximum extent possible utilizing unaffected power sources and circuit routes. Additionally, the system provides improved information on where to dispatch line crews responding to fault and outage conditions; thereby, reducing the time to detect and remedy potentially dangerous conditions.

Impact of the Activity on Wildfire Risk

The wildfire risk is reduced by BVES's ability to quickly isolate detected faults.

Impact of the Activity on PSPS Risk

This program would also allow for additional sectionalization to minimize the impact of PSPS events.

Updates to the Activity

The FLISR system was completed in 2022 and is fully operational. BVES will look to expanding FLISR capability into the 4 kV distribution system where it is possible due to circuit configurations.

Fuse TripSaver Automation

Overview

This initiative is aimed at reducing the risk of ignitions due to conventional fuses and also to increase situational awareness of the electric distribution system, rapidly detecting fault conditions, and restoring the fuses remotely through the SCADA system. The Fuse TripSaver Automation is scheduled to connect and automate 160 Fuse TripSavers to the SCADA network over a four-year period. BVES finished replacing all conventional fuses to current limiting and electronic fuses in 2021. However, in order to fully optimize surveillance of the system, BVES plans to automate the fuses by integrating the devices with the SCADA network.

Impact of the Activity on Wildfire Risk

The reduction of conventional fuses that tend to spark by replacing them with electronic fuses greatly reduces the risk of wildfires. By automating the Fuse TripSavers BVES will be able to rapidly and remotely switch the devices to “manual” to prevent them from testing following a fault detection (over current) on “dry”and “very dry” days.

Impact of the Activity on PSPS Risk

By integrating the newly installed electronic fuses with the SCADA network, using a fault condition detection, the system can intelligently restore the fuses as soon as possible reducing the risk of PSPS.

Updates to the Activity

The project is planned for 2023 and will be completed in 2026.

Server Upgrade Project

Overview

This initiative supports the SCADA network configuration by providing enough physical space and controls to allow for flexibility, reliability, and security in operating the automated SCADA network. This will enable the integration of remote devices that will allow BVES to detect and react to faults, outages, and potential fire risk across its system. This upgrade project is a necessary component to upgrading the SCADA network. The Server Upgrade Project converts space at BVES into a fully compliant server room with security and environmental controls, backup power, server racks and conduit, and server equipment to fully support BVES’s SCADA network.

Impact of the Activity on Wildfire Risk

The project upgrade allows for the integration of more intelligent remote devices that will assist in the monitoring and remote control of devices which will reduce wildfire risks.

Impact of the Activity on PSPS Risk

Same as with the reduction of wildfire risks the expansion on the SCADA network will help expand the automation devices that reduce the risk of PSPS.

Updates to the Activity

The project is planned for 2023

<u>Distribution Management Center Program</u>

Overview

This initiative supports the SCADA network configuration, which aims to construct a fully equipped distribution management center to permit monitoring and control of the sub-transmission and distribution electrical assets, monitor and operate the OMS, update interactive voice response (IVR) and company website and social media, and provide for dispatch of repair crews. BVES plans to install a Distribution Management Control Center (DMCC) with the following equipment and applications that would provide substantially greater information capabilities to distribution decision makers relevant to the following functional areas: (1) Energy Resources; (2) T&D Assets; (3) SCADA, Outage Management System, GIS & Other Applications; (4) Weather Information; (5) HD Cameras; (6) Media Access (Internet, BVES Website & Social Media, Local Radio, TV, etc.); (7) Communications Equipment; and (8) Dispatch Services.

Impact of the Activity on Wildfire Risk

A fully integrated control management system is integral to maintaining optimal awareness into the system as well as management of communication methods internally and externally, and remote control of switching and fuse devices. This will assist with providing BVES monitor real-time data improve control and reduce wildfire risk.

Impact of the Activity on PSPS Risk

Similar to the reduction of wildfire risks, the expansion on this project will help expand the situational awareness of the system and remote control and operation thereby reducing the risk of PSPS.

Updates to the Activity

The conceptual planning for such a facility is scheduled to start in 2024. A detailed design plan will be developed in 2023 with the facility anticipated to be constructed in 2024 to coincide with the SCADA and Grid Automation efforts being completed as the DMCC facility comes online.

8.1.2.9 Line Removal in HFTD (Tracking ID: GD_18)

N/A. BVES does not have a line removal program or plans to remove lines currently. A program will be established if line removal is needed in the future.

8.1.2.10 Other Grid Topology Improvements to Minimize Risk of Ignitions (Tracking ID: GD_19)

Tree Attachment Removal Program

Overview

This Tree Attachment Removal Program 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. Although this infrastructure approach initially reduces costs, it inherently introduces ignition risk by holding energized wires in direct proximity to vegetation.

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 high-risk circumstances, BVES has planned to remove all tree attachments by the end of 2026. Elimination of tree attachments will enhance the safety and reliability of the distribution system and reduce the risk of wildfires.

Impact of the Activity on PSPS Risk

This activity is not expected to impact PSPS Risk.

Updates to the Activity

BVES had approximately 1,207 legacy tree attachment service connections in its service area (2019 inventory count), mostly located in USFS controlled areas. As of December 31, 2021, BVES has removed 644 tree attachments and installed 223 new poles. BVES estimates that the remaining 563 tree attachments will be removed by the end of 2026. 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.

Expulsion fuse replacement

Overview

Fuses are devices that protect the distribution system from faulted or damaged lines and equipment. BVES has historically used conventional "expulsive" fuses to protect lines. From 2019-2021 BVES replaced all conventional fuses, installing electronic programmable fuses (vacuum style) system-wide such as the S&C TripSaver II. There are no expulsion fuses in the BVES system. BVES also installed current limiting fuses and electronic fuses that expel no materials, limit the available fault current, and may even reduce the duration of faults.

Impact of the Activity on Wildfire Risk

Conventional fuses expel hot particles and gases when operated, which can start wildfires. Following SB 901 and the increased availability of alternative fusing, utilities are replacing conventional fuses with current limiting fuses (non-expulsion, ELF) on branch line fusing opportunities system wide, BVES replaced all of its conventional fuses. By replacing every fuse with the potential to spark and impact dry vegetation, BVES's replacement with non-expulsion fuses reduces the risk of a fusing operation to near zero. From 2015 through 2019, BVES had 84 conventional fuses operating. In 2020, there were a total of 23 fuse events. However, due to the effectiveness of this project, only four were conventional fuse events (the others were 16 ELF and 3 TripSavers fuse events). In 2021, there were three events, one in January and two in February. Until recently, BVES had approximately 3,114 conventional fuses, all in high-risk wildfire areas. As part of this initiative, BVES replaced approximately 536 conventional fuses with electronic fuses and approximately 2,578 conventional fuses with ELFs. As of December 31, 2021, BVES had replaced all its conventional fuses. This program shifted in 2022 to normal business operations of maintenance and operations (replace blown ELF with new ELF and maintain Fuse TripSavers per manufacturer's recommendations) as described in Section 8.1.4.5.

Impact of the Activity on PSPS Risk

This project has minimal impact on PSPS risk.

Updates to the Activity

BVES will apply any lessons learned throughout the progression of the program. Additionally, BVES intends to utilize the programmable features of the electronic programmable fuses once its SCADA network is fully established in its service area. This will allow BVES to optimize fuse settings remotely and rapidly for various weather and operating conditions.

8.1.2.11 Other Grid Topology Improvements to Mitigate or Reduce PSPS Events (Tracking ID: GD_20)

Switch and Field Device Automation Project.

Overview

This project aims to automate and connect to Bear Valley's SCADA network 28 sub-transmission (34 kV) switches and 20 distribution switches over four years (2023 to 2026) 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. As indicated in the table below, 32 switches will be replaced with automated SCADA enabled switches, 13 switches will be motorized (motor operator installed to existing switch) and SCADA enabled, and one new switch will be added to the sub-transmission system to allow isolation of the Moonridge and Bear Mountain substations from the sub-transmission system for maintenance and fault isolation purposes. Automated switches would have battery backup power to permit remote connectivity and operation on a complete loss of power.

Impact of the Activity on Wildfire Risk

The 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. The project will allow BVES to 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. It will also allow 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.

Impact of the Activity on PSPS Risk

If Bear Valley were to lose some or all of its power supplies from SCE due to a SCE-directed PSPS, 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.

This effort will also support actions taken to mitigate or reduce 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.

Updates to the Activity

BVES has completed prior assessments of device needs and concluded this activity in 2019. In 2023, BVES will implement a new project to install additional switching devices for supply transfer ability to mitigate load loss or PSPS event impact.

BVPP Phase 4 Upgrade Project

Overview

This program is aimed at reducing the impacts of power outages from proactive de-energization and preserving essential services by improving the reliability of the Bear Valley Power Plant (BVPP). The Phase Three (2022) upgrades will include installing new catalyst housing directly above the engine. New placement will reduce heat loss and improve emissions bandwidths. The catalyst housing will include the double stacked element system to provide additional assistance in meeting emissions requirements. It also relocates oil and water piping, battery boxes, and controller stands while increasing accessibility and safety. The project will also address several age-related issues and align each generator to limit vibrations and abnormal wear on the engine.

Phase Four activities (2023) will include installing updated engine controls on all engines to a current controls system that will allow efficient start/stop functions, consolidated controls, and synchronization monitoring. Also, the plan is to replace the Detonation Sensing Module (DSM) Controls on all engines with a detcon system that will allow for visual DSM monitoring and repair any faulty wiring. Lastly, the project is scheduled to replace the governor speed control systems on all engines with a ProAct system and EX Gen control.

Impact of the Activity on Wildfire Risk

This activity will not impact wildfire risk.

Impact of the Activity on PSPS Risk

Implementing this project as described in this section would result in significantly reducing the risk to Bear Valley's customers having to endure extended outages due to a loss of energy supplies as a result of SCE invoking a PSPS event on power lines that supply Bear Valley. Generally, during Santa Ana winds, which is when it is likely that SCE would invoke a PSPS event, the temperatures in Bear Valley often drop below freezing at night which leave customers without heat. This is potentially dangerous to elderly, AFN, and other vulnerable customers; therefore, this project aims to reduce public risk.

Updates to the Activity

BVES has outlined the Four (2023) activities planned for this initiative in the above section. BVES will consider any future upgrades when these phases are completed.

8.1.2.12 Other Technologies and Systems Not Listed Above (Tracking ID: GD_21 – GD_24)

Safety and Technical Upgrades to Substations

Overview

This initiative covers the Safety and Technical Upgrades to Substations and the Tree Attachment Removal Program.

This initiative category accounts for the incremental repair, maintenance, and replacement work associated with substations to function safely, reliably, and properly to reduce increased ignition risk. BVES recently converted the existing Palomino Substation from an overhead-type to a pad-mounted design with dead front SCADA-enabled. This will improve the safety, reliability, and efficiency of the substation by eliminating a wiring configuration that poses a safety and fire risk due to its exposure to the elements, such as vegetation contact. Additionally, BVES has replaced all substation equipment with enclosed pad mounted transformers, voltage regulators, re-closers, and bus work, further enhancing wildfire mitigation and reliability.

Impact of the Activity on Wildfire Risk

The existing Palomino substation had 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 a wildfire or extensive power outage. 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. This work is performed in Tier 2 as there are no substations in Tier 3. BVES will prioritize this effort based on need and relative risk.

Impact of the Activity on PSPS Risk

This project does not substantially impact PSPS risk.

Updates to the Activity

BVES plans, in 2025, to perform partial safety and technical upgrades to the Maltby, Moonridge, and Lake Substations. This will include replacing overhead regulators with pad-mounted regulators, installing pad-mounted IntelliRupter switches, which will convert the substation to be fully underground, and lastly, updates to substation controls. BVES will also continue to exchange information with other utilities on the available substation upgrades and their cost versus risk benefits.

8.1.3 Asset Inspections

In this section, the electrical corporation must provide an overview of its processes and procedures for inspecting it assets.

The electrical corporation must first summarize details regarding the inspection process in Table 8-6. The table must include the following:

- ***Type of inspection** – i.e., distribution, transmission, or substation*
- ***Inspection program name** – Identify various inspection programs within the electrical corporation*
- ***Frequency or trigger** – Identify the frequency or triggers, such as inputs from the risk model. Indicate differences in frequency or trigger by HTFD Tier, if applicable*
- ***Method of inspection** – Identify the methods used to perform the inspection (e.g., patrol, detailed, aerial, climbing, and LiDAR)*
- ***Governing standards and operating procedures** – Identify the regulatory requirements and the electrical corporation's procedures/processes*

Table 8-6 Vegetation Management Inspection Frequency, Method, and Criteria

Type	Inspection Program	Frequency or Trigger (Note 1)	Method of Inspection (Note 2)	Governing Standards & Operating Procedures	Section
Transmission	N/A	N/A	N/A	N/A	
Distribution	Detailed Inspection	5 Years		GO 165 & GO 95 (Rule 18)	8.1.3.1
Distribution	Patrol Inspection	Annual		GO 165 & GO 95 (Rule 18)	8.1.3.2
Distribution	UAV Thermography Inspection	Annual		GO 95 (Rule 18)	8.1.3.3
Distribution	UAV HD Photography/Videography	Annual		GO 165	8.1.3.4
Distribution	LiDAR Inspection	Annual		GO 95 (Rule 18)	8.1.3.5

Distribution	3rd Party Ground Patrol	Annual		GO 165 & GO 95	8.1.3.6
Distribution	Intrusive Pole Inspection	Per GO 165		GO 165	8.1.3.7
Substation	Substation Inspection	Monthly		GO 174	8.1.3.8

Note 1: The electrical corporation must provide electrical corporation-specific risk-informed triggers used for asset inspections.

Note 2: The electrical corporation must provide electrical corporation-specific definitions of the different methods of inspection.

The electrical corporation must then provide a narrative overview of each vegetation inspection program identified in the above table; Sections 8.2.2.1. provides instructions for the overviews. The sections should be numbered 8.1.3.1 to Section 8.1.3.n (i.e., each vegetation inspection program is detailed in its own section).The electrical corporation must include inspection programs it is discontinuing or has discontinued since the last WMP submission; in these cases the electrical corporation must explain why the program is being discontinued or has been discontinued.:

8.1.3.1 Detailed Inspection Program

Process

In this section, the electrical corporation must provide an overview of the individual asset inspection program, including inspection criteria and the various inspection methods used for each inspection program.

Include relevant visuals and graphics depicting the workflow and decision-making process the electrical corporation uses for the inspection program (see the example in Figure 8-1).

A “detailed inspection” is a more careful visual and diagnostic exam 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 risk 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 the 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.

Frequency or Trigger

In this section, the electrical corporation must identify the frequency (including how frequency may differ by HFTD Tier or other risk designation[s]) or triggers used in the inspection program, such as inputs from the risk model.

If the inspection program is schedule-based, the electrical corporation must explain how it uses risk prioritization in the scheduling of the inspection program to target high-risk areas. If the electrical corporation does not use risk prioritization in the scheduling of the inspection program, it must explain why.

BVES conducts these inspections at least once every five years in compliance with GO 165 and GO 95 (Rule 18). BVES divides its system up and each year conducts Detailed Inspections such that each circuit is Detailed Inspected at least every five years.

8.1.3.2 Patrol Inspection Program

Process

In compliance with GO 165, BVES'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. BVES's Field Inspector performs the patrol inspections. The Field Inspector is required to be a Journeyman Lineman experienced in inspection of electric transmission and distribution facilities and power lines.

Frequency

Patrol inspections are conducted annually and cover the entirety of BVES's overhead facilities. Because all of BVES's service territory is in HFTD Tier 2 or Tier 3, risk prioritization scheduling is not used in assigning the patrol inspections.

8.1.3.3 UAV Thermography

Process

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.

Frequency

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

8.1.3.4 UAV HD Photography/Videography

Process

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 and LiDAR inspections. 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 are able to 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.

Frequency

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

8.1.3.5 LiDAR Inspection

Process

BVES conducts one LiDAR sweep of its entire service area per year to evaluate the effectiveness of clearance efforts and identify potential wildfire hazards. This is an enhanced inspection using LiDAR (Light Detection and Ranging) inspections and analysis, 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. BVES 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 BVES's electrical system to the road network and the tree canopy that is typical of distribution systems, truck-mounted mobile LiDAR is utilized more often because it is 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 and handled in the same manner as described above. When BVES receives the LiDAR survey report, each finding is investigated by qualified personnel in evaluating asset conditions to validate the actual conditions and reassign the priority per GO 95, if deemed appropriate. The LiDAR contractor immediately informs 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. Finally, the results of LiDAR surveys are validated against other asset inspections to evaluate the quality and effectiveness of each inspection type.

Frequency

LiDAR inspections are conducted annually and cover the entirety of BVES's overhead facilities. All of BVES's service territory is in HFTD Tier 2 or Tier 3 and is very compact and done over a short period of time, therefore risk prioritization scheduling is not used in assigning these inspections.

8.1.3.6 3rd Party Ground Patrol

Process

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 BVES's Field Inspector performs. BVES contracts experienced and qualified electrical distribution asset inspection contractors to perform this ground patrol inspection.

BVES believes 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 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.

Frequency

The 3rd Party Ground Patrol inspections are conducted annually and cover the entirety of BVES's overhead facilities. Because all of BVES's service territory is in HFTD Tier 2 or Tier 3, risk prioritization scheduling is not used in assigning these inspections.

8.1.3.7 Intrusive Pole Inspection

Process

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.

Frequency

BVES conducts Intrusive Pole Inspection on a cycle that maintains compliance with GO 165 based off of 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 up on 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.

8.1.3.8 Substation Inspection

Process

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.

Frequency

Substation Inspection – BVES conducts Substation Inspections for all 13 substations on a month 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.

8.1.3.9 Inspection Accomplishments, Roadblocks, and Updates

BVES has established robust asset inspection routines that go beyond GO-165 requirements and include state-of-the-art inspection techniques that include LiDAR surveys, UAV HD Photography & Thermography, and 3rd party Ground Patrols. Bear Valley has also upgraded its data governance, including geographic locational data, for its assets, inspections, findings, and corrections.

8.1.4 Equipment Maintenance and Repair

In this section, in addition to the information described above regarding distribution, transmission, and substation inspections, the electrical corporation must provide a brief narrative of maintenance programs. As a narrative, the electrical corporation must include its strategy for maintenance, such as whether the electrical corporation replaces or upgrades facilities/equipment proactively (for example, an electrical corporation may monitor dissolved gases in its transformers to detect potential transformer failures to alert engineering and maintenance personnel or component lifecycle management) or if it runs its facilities/equipment to failure. The narrative must include, at minimum, the following types of equipment:

- *Capacitors*
- *Circuit breakers*
- *Connectors, including hotline clamps*
- *Conductor, including covered conductor*
- *Fuses, including expulsion fuses*
- *Distribution poles*
- *Lightning arrestors*
- *Reclosers*
- *Splices*
- *Transmission poles/towers*
- *Transformers*
- *Other equipment not listed*

8.1.4.1 Capacitors

A detailed inspection is performed on the 24 capacitor banks each year. The inspection for 2022 was completed in July 2022. This is 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 and reduce the likelihood of faults or failures that may result in ignitions. BVES does not run its capacitors to failure.

Capacitor banks are also inspected at the following times:

- During system detailed inspections every five years per GO 165 system patrol
- Patrol inspections - BVES performs two full patrols of its system per year (exceeding the GO 165 requirement)
- UAV thermography and HD photography/videography (exceeding the GO 165 requirement)
- 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.

BVES plans to replace six capacitor banks per year beginning in 2023. The project aims to replace 24 capacitor banks from 2023 – 2026. The new capacitor banks will replace significantly aging (>40 years-old) manually operated 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.

The new capacitor banks will be 450kVAR 3-phase units connected to the SCADA system for remote operation, control and monitoring of performance. In addition, the project will study the locations that will result in optimized voltage support and control. Connectivity to SCADA will be via radio/cellular data transfer equipment and the BVES service area fiber optic network. This will allow BVES to control voltage by placing or removing the capacitor banks from service, as needed, without sending a crew to manually operate the capacitor banks. Additionally, the capacitor banks will be continuously monitored to prevent overheating or excessive voltage which may lead to catastrophic failure.

Table 8-7 Capacitor Replacement List

Year	Element Name	Type	Phasing	Upline Source	Upline Feeder	Address	Status
2023	C12525BV	Capacitor	ABC	Village	BoulderBreaker	39649 Big Bear Blvd, Big bear Lake, CA 92333	ONLINE
2023	C11207BV	Capacitor	ABC	Village	Boulder Circuit	South of, 40074 Big Bear Blvd, Big Bear Lake, CA 92315	OFFLINE, DAMAGED
2023	C7027BV	Capacitor	ABC	Maltby	ErwinLake Circuit	1048 Willow Ln, Big Bear, CA 92314	ONLINE
2023	C6116BV	Capacitor	ABC	Maltby	ErwinLake Circuit	866 Lakewood Dr, Big Bear, CA 92314	OFFLINE

2023	C3216BV	Capacitor	ABC	Fawnskin	North Shore Circuit	39222 N Shore Dr, Big Bear, CA 92314	ONLINE
2023	C10014BV	Capacitor	ABC	Maltby	Paradise Circuit	116 W Sherwood Blvd, Big Bear, CA 92314	OFFLINE

8.1.4.2 Circuit breakers

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 breaker inspections at substations are mandated by the CPUC through 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 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.

8.1.4.3 Connectors, including hotline clamps

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
- Patrol asset inspection
- LiDAR asset inspection
- UAV Thermography asset inspection
- UAV Photography/Videography asset inspection
- 3rd Party Ground Patrol asset inspection

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

In the last five years, BVES replaced approximately six hotline clamps due to the limited number in its system and its efforts to not introduce any new additional hotlines as stated above. Currently, it is BVES's policy that when a hotline clamp is found, to note and report any hotline clamp locations to the Field Operations Supervisor and Engineering staff for tracking in GIS system. Upon identification, the hotline clamp is identified for removal as soon as feasible. Once removed from the system, GIS is updated to reflect its removal.

8.1.4.4 Conductor, including covered conductor

BVES will maintains 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
- Patrol asset inspection
- LiDAR asset inspection
- UAV Thermography asset inspection
- UAV Photography/Videography asset inspection
- 3rd Party Ground Patrol asset inspection

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

Regarding covered conductors, BVES will maintain the installed covered conductor in accordance with prescribed maintenance standards and industry best practices. This include remediation and adjustments to installed covered or insulated conductors. This will reduce the chance of degradation to the covered wire and potential for ignition sources to develop.

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.

8.1.4.5 Fuses, including expulsion fuses

As of December 31, 2021, BVES had replaced all of its conventional fuses, installing ELF Type (Tripsaver) electronic programmable fuses (vacuum style) system-wide such as the S&C TripSaver II. BVES also installed current limiting fuses and electronic fuses that expel no materials, limit the available fault current, and may even reduce the duration of faults. BVES will maintain these fuses as described and has established a separate initiative for maintenance activities. Fuses are inspected as follows:

- Detailed asset inspections
- Patrol asset inspection
- LiDAR asset inspection
- UAV Thermography asset inspection
- UAV Photography/Videography asset inspection
- 3rd Party Ground Patrol asset inspection

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

8.1.4.6 Distribution poles

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 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 preventive maintenance to identify poles at risk

8.1.4.7 Lightning arrestors

BVES installs lightening arrestors that are approved for use in all areas of California in accordance with GO-95. Lightning arrestors are inspected via BVES's asset inspections (detailed, patrol, thermography, UAV photography) and defective arrestors are replaced. Additionally, during pole replacements arrestors are also replaced.

8.1.4.8 Reclosers

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 in accordance with GO 174. In 2023, BVES will start to automate additional field switches as discussed below.

8.1.4.9 Splices

BVES rarely uses splices. BVES's asset inspections (detailed, patrol, thermography, UAV photography) inspect for splices and defective splices are repaired. Additionally, during reconductor work, splices are removed.

8.1.4.10 Transmission Poles/Towers

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

8.1.4.11 Transformers

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

BVES has 3,141 service transformers and performs the following operations and maintenance on them:

- Detailed asset inspections (visual inspection checking for oil leakage, casing bulging, casing corrosion and integrity)
- Patrol asset inspection (visual inspection checking for oil leakage, casing bulging, casing corrosion and integrity)
- LiDAR asset inspection
- UAV Thermography asset inspection
- UAV Photography/Videography asset inspection
- 3rd Party Ground Patrol asset inspection

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 above operations and maintenance actions and generally as part of a major substation upgrade project. BVES preventive maintenance and replacement program is intended to replace transformers before they fail.

8.1.4.12 Other Equipment Not Listed

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

8.1.5 Asset Management and Inspection Enterprise System(s)

In this section, the electrical corporation must provide an overview of Inputs, operation of, and support for centralized asset management and inspection enterprise system(s) updated based upon inspection results and activities such as hardening, maintenance, and remedial work. This overview must include discussion of:

- *The electrical corporation's asset inventory and condition database*
- *Describe the utilities internal documentation of its database(s)*

- *Integration with systems in other lines of business*
- *Integration with the auditing system(s) (see QA/QC section below)*
- *Describe internal processes for updating enterprise system including database(s) and any planned updates*
- *Any changes to the initiative since the last WMP submission and a brief explanation as the why those changes were made. Include any planned improvements or updates to the initiative and timeline for implementation*

BVES improved its asset management and inspection enterprise system over the last few 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.

BVES recognizes the importance of carefully tracking and managing WMP data for all its activities and initiatives performed in accordance with this WMP. BVES records and manages data collected from numerous sources, in varying formats, and in several storage locations in the execution of its wildfire mitigation efforts. Table 8-8 below highlights the types of data collected and the repository in use by BVES for such data.

Table 8-8 Detailed Data Information

Data Source	Storage Location	Data	Planned Next Steps	Storage Type (Excel, GIS, etc.)	Update Process
Vegetation Management	Partners & Spreadsheet Database	Vegetation findings and completed sections	Migration to iRestore (cloud-based) software Oct. 2022	Excel, Geo Database	Manual
Substation Inspections (GO 174)	Paper-based-database	Asset inventory, type, and condition	Migration to iRestore (cloud-based) software Oct. 2022	Binder	Manual
GO 165 Inspections	iRestore	Asset inventory, asset/vegetation findings and condition	Add vegetation management inventory, tracking	Cloud-based, Geo Database	Via mobile phone, tablet
LiDAR Inspections	Spreadsheet and web portal	Asset/vegetation findings and condition	Planning to import into Geo Database	Excel, Shapefile	Manual
UAV Inspections	Spreadsheet and web portal	Asset/vegetation findings and condition		Excel, Geo Database	Manual
Covered Conductor	Spreadsheet	Asset inventory		Excel, Geo Database	Manual
Pole Replacement	Spreadsheet	Asset inventory, inspection dates, findings, and condition		Excel, Geo Database	Manual

Pole Remediation	Spreadsheet	Asset inventory, inspection dates, findings, and condition		Excel	Manual
Pole Assets	Spreadsheet	Asset inventory, inspection dates, findings, and condition		Excel	Manual
Fire Wrap	Spreadsheet	Asset inventory, inspection dates, findings, and condition		Excel, Geo Database	Manual
Fuse Replacement	Spreadsheet	Asset inventory, inspection dates, findings and condition		Excel, Geo Database	Manual
VM QA/QC Inspections	Web Portal	Vegetation findings and completed sections		Excel	Via tablet
Asset Inspection QA/QC	Spreadsheet	Asset inventory, inspection dates, findings, and condition		Excel	Manual
Outage Log	Spreadsheet	Outage time/date, duration, and cause		Excel, Geo Database	Manual
Daily wildfire risk	Technosylva	Ignition and spread potential based on current, expected conditions	Add PSPS threshold indicators	Geo Database	Vendor automated updates

BVES is continually updating its data gathering and managing resources and tools. Equally important is having the ability to track electric system upgrades in a GIS database. Having this information in a standard format supports BVES's ability to continuously improve its risk mitigation process.

BVES GIS system does not currently support the sharing of data with key stakeholder agencies, such as the CPUC and CAL FIRE, but BVES provides its data in accordance with regulatory requirements. To support the above, BVES has an ongoing initiative to update GIS records in the format agreed upon by the OEIS.

Currently, most of these systems are standalone but BVES is working to integrate them with its other systems. Regarding BVES, interaction with other lines of business is less of a concern than larger utilities as the structure is essentially flat with most staff members responsible for multiple roles affecting different parts of the utility’s operations.

BVES can share its data with both internal and external QA and QC reviews and activities. However, BVES does not have an automated "auditing system." BVES will continue to monitor such systems for their effectiveness at a reasonable cost.

8.1.6 Quality Assurance / Quality Control (QA/QC)

In this section, the electrical corporation must provide an overview of its QA/QC activities for asset management by inspection program. This overview must include:

- *Reference to procedure/program documenting QA/QC activities.*
- *How the sample sizes are determined and how the electrical corporation ensures the samples are representative*
- *Qualifications of the auditors*
- *Documentation of findings and how lessons learned based on those findings are incorporated into training and/or procedures*
- *Any changes to the initiative since the last WMP submission and a brief explanation as the why those changes were made. Include any planned improvements or updates to the initiative and timeline for implementation*
- *Tabular information (Table 8-7 is an exemplar of the appropriate level of detail) that includes:*
- *Sample sizes*
- *Type of QA/QC performed (e.g., desktop or field)*
- *Resulting pass rates, starting in 2022*
- *Yearly target pass rate for the 2023-2025 Base WMP cycle*

Table 8-9 Grid Design and Maintenance QA/QC Program

Activity Being Audited	Sample Size	Type of Audit	Audit Results 2022	Yearly Target Pass Rate for 2023-2025
Covered Conductor Installation	100% Inspection of installations by contractor	Verify Contractor's Construction and installation	Completed	99%
Tree Attachment Removal Program	100% inspection of installations by contractor	Verify Contractor's Construction and installation	Completed	99%
Grid Design and Maintenance	20 Inspections per year	QC of Grid Design and Maintenance	Beginning in 2023	99%

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.

BVES'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 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.

Table 8-10 below demonstrates the quality control program tracking.

Table 8-10 Quality Control Program Tracking

Start Pole #	End Pole #	Start STA #	End STA #	New Wire Size	Total Circuit Length	Conductor Qty	Circuit	Install Date	CM	BVES QC Date	BVES Inspector	BVES QC Personnel
12439BV	11918BV / 14278BV	60	69-70	394	1250	3	Shay 34kV	6/10/2021	0.24	6/11/2021	Field Inspector	Anthony Rivera
12439BV	11918BV / 14278BV	60	69-70	394	1250	4	Pioneer 4kV	6/10/2021	0.24	6/11/2021	Field Inspector	Anthony Rivera
12447BV	14824BV	78	82-83	1/0	525	2	Pioneer 4kV	6/24/2021	0.10	6/25/2021	Field Inspector	Anthony Rivera
14826BV	14828BV	91	94-95	1/0	575	2	Pioneer 4kV	6/24/2021	0.11	6/25/2021	Field Inspector	Anthony Rivera
11298BV	12439BV	60	61	1/0	60	2	Pioneer 4kV	6/10/2021	0.01	6/11/2021	Field Inspector	Anthony Rivera
12433BV	12447BV	40	78	394	3975	4	Pioneer 4kV	6/18/2021	0.75	7/8/2021	Field Inspector	Anthony Rivera
12433BV	12447BV	40	78	394	3975	3	Shay 34kV	6/18/2021	0.75	7/8/2021	Field Inspector	Anthony Rivera
12433BV	12637BV	40	26	394	1865	4	Pioneer 4kV	7/2/2021	0.35	7/19/2021	Field Inspector	Anthony Rivera
12433BV	12637BV	40	26	394	1865	3	Shay 34kV	7/2/2021	0.35	7/19/2021	Field Inspector	Anthony Rivera
12426bv	11232bv	48	52	1/0	663	2	Pioneer 4kV	7/9/2021	0.13	7/19/2021	Field Inspector	Anthony Rivera
12445bv	1211696ctc	85	87	1/0	110	2	Pioneer 4kV	7/9/2021	0.02	7/19/2021	Field Inspector	Anthony Rivera
14763BV	9285BV / 14815BV	1	23/24	394	2726	4	Pioneer 4kV	7/15/2021	0.52	7/19/2021	Field Inspector	Anthony Rivera
14763BV	9285BV / 14815BV	1	23/24	394	2726	3	Shay 34kV	7/15/2021	0.52	7/19/2021	Field Inspector	Anthony Rivera
9774BV	12557BV	5	23	394	2182	4	Sunset 4kV	9/24/2021	0.41	10/1/2021	Field Inspector	Anthony Rivera
9774BV	12557BV	5	23	394	2182	3	Shay 34kV	9/24/2021	0.41	10/1/2021	Field Inspector	Anthony Rivera
12557BV	11095BV / 14776BV	5	34/35	394	1850	3	Shay 34kV	10/8/2021	0.35	10/22/2021	Field Inspector	Anthony Rivera
12557BV	11095BV / 14776BV	5	34/35	394	1850	4	Sunset 4kV	10/8/2021	0.35	10/22/2021	Field Inspector	Anthony Rivera
9772BV / 14765BV	9774BV	3-4	5	394	180	3	Shay 34kV	10/22/2021	0.03	10/22/2021	Field Inspector	Anthony Rivera
9772BV / 14765BV	9774BV	3-4	5	394	180	4	Sunset 4kV	10/22/2021	0.03	10/22/2021	Field Inspector	Anthony Rivera
11095BV / 14776BV	13864BV	34-35		394	60	4	Sunset 4kV	10/22/2021	0.01	10/22/2021	Field Inspector	Anthony Rivera

11095BV / 14776BV	13864BV	34-35		394	60	3	Shay 34kV	10/22/2021	0.01	10/22/2021	Field Inspector	Anthony Rivera
10543BV	14829BV	23	96/97	394	3770	4	Shay 34kV	10/22/2021	0.71	10/29/2021	Field Inspector	Anthony Rivera
10543BV	14829BV	23	96/97	394	3770	3	Sunset 4kV	10/22/2021	0.71	10/29/2021	Field Inspector	Anthony Rivera
14795BV	14803BV	42	59	394	1175	4	Sunset 4kV	10/28/2021	0.22	11/12/2021	Field Inspector	Anthony Rivera
BV10985	14843BV	25	27	394	199	4	Paradise 4kV	11/16/2021	0.04	11/24/2021	Field Inspector	Anthony Rivera
14843BV	14834BV	27	29	394	199	4	Paradise 4kV	11/16/2021	0.04	11/24/2021	Field Inspector	Anthony Rivera
14834BV	14832BV	29	31	394	151	4	Paradise 4kV	11/16/2021	0.03	11/24/2021	Field Inspector	Anthony Rivera
14832BV	9044BV	31	3	394	227	4	Paradise 4kV	11/16/2021	0.04	11/24/2021	Field Inspector	Anthony Rivera
14839BV	BV10985	24	25	394	59	4	Paradise 4kV	11/23/2021	0.01	11/24/2021	Field Inspector	Anthony Rivera

Current plans for next year include applying any lessons learned and gathered throughout the year and further improving BVES's QA/QC program for asset inspection. BVES will monitor the results of its asset management QA/QC programs and implement improvements as warranted. BVES will also exchange information with other utilities to determine best practices in asset management QA/QC for consideration in BVES's program.

8.1.7 Open Work Orders

In this section, the electrical corporation must provide an overview of the process it uses to manage its open work orders. This overview must include a brief narrative that provides:

- *Reference to procedures/programs documenting the work order process. The electrical corporation must provide a summary of these procedures or provide a copy in the supporting documents location on its website.*
- *A description of how work orders are prioritized based on risk.*
- *A description of the plan for eliminating any backlog of work orders (i.e., open work orders that have passed remediation deadlines), if applicable.*
- *A discussion of trends with respect to open work orders*

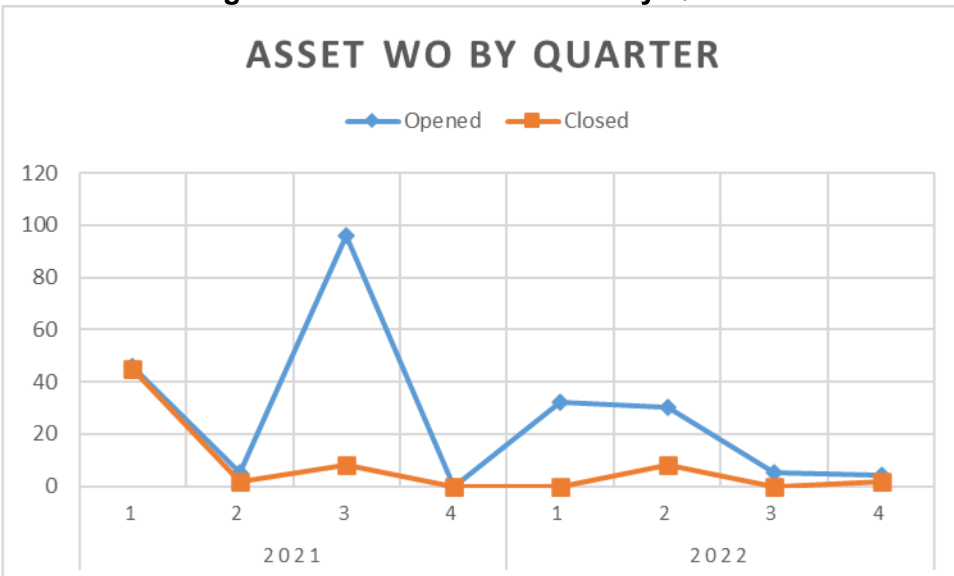
In addition, each electrical corporation must:

- *Graph open work orders over time as reported in the QDRs (Table 2, metrics 8.a and 8.b).*
- *Provide an aging report for work orders past due (Table 8-8 provides an example).*

Table 8-11 Past Due Asset Work Orders

HFTD Area	0-30 Days	31-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

Figure 8-2 Asset Work Orders By Quarter



All open tasks and work orders will be tracked in iRestore. Additionally, all inspection findings will generate a new work order which will also be tracked in iRestore. BVES began this effort in Q1 2023.

8.1.8 Grid Operations and Procedures

In this section, the electrical corporation must discuss the ways in which operates its system to reduce wildfire risk. The equipment settings discussion must include the following:

- *Protective equipment and device settings*
- *Automatic recloser settings*
- *Settings of other emerging technologies (e.g., rapid earth fault current limiters)*

For each of the above, the electrical corporation must provide a narrative on the following:

- *Settings to reduce wildfire risk*
- *Analysis of reliability/safety impacts for settings the electrical corporation uses*
- *Criteria for when the electrical corporation enables the settings*
- *Operational procedures for when the settings are enabled*
- *The number of circuit miles capable of these settings*
- *An estimate of the effectiveness of the settings*

8.1.8.1 Equipment Settings to Reduce Wildfire Risk

In this section, the electrical corporation must discuss the ways in which operates its system to reduce wildfire risk. The equipment settings discussion must include the following:

- *Protective equipment and device settings*
- *Automatic recloser settings*

- *Settings of other emerging technologies (e.g., Rapid Earth Fault Current Limiters)*

For each of the above, the electrical corporation must provide a narrative on the following:

- *Settings to reduce wildfire risk*
- *Analysis of reliability/safety impacts for settings the electrical corporation uses*
- *Criteria for when the electrical corporation enables the settings*
- *The number of circuit miles capable of these settings*
- *An estimate of the effectiveness of the settings*
- *The electrical corporation's operations procedures for response to off-normal events*

Protective equipment and device settings

Grid operations and protocols encompass company procedures related to wildfires, special work procedures, and wildfire response team definitions. These practices help the utility manage risk on a day-to-day basis and during wildfire high risk periods.

Understanding the electric system load/demand allows BVES 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. Generally, since the winter months bring the heaviest load/demand on the BVES distribution system, BVES optimizes the system for safety and reliability during such time. These months are often wet and do not typically pose significant wildfire risks. Following the winter season, the operational focus becomes more defensive and optimized for wildfire prevention, given the hot, dry climate. Specifically, the system uses the following protocols:

1. From approximately November 1st through March 31st, the system is focused on safety and reliability with higher load settings to accommodate higher demand due to colder temperatures and reclosers set to automatic.

2. From approximately April 1st through October 31st, BVES adopts a more defensive operational scheme during the non-winter months. To accomplish this, the utility enacts certain operational settings:

    a. All TripSavers fuses are set to not reclose.

    b. Auto-Recloser field trip settings adjusted for summer load.

    c. Radford 34.5 kV line de-energized.

Although BVES generally follows a strict schedule, the utility monitors conditions, using the NFDRS, to determine if additional precautions should be taken. Further, BVES staff and BVES's weather consultant review the NFDRS on a weekly basis or more frequently during high fire threat periods to make advanced preparations and on a daily basis to determine if additional steps should be taken. In short, overall system configuration is optimized for fire prevention from approximately April 1 to October 31, using the seasonal characteristics of BVES's climate and load profile. The system is then further adjusted based on the seven-day NFDRS forecast, as well as other operational and weather information available to BVES.

BVES monitors the NFDRS fire danger forecast each day and then determines the proper operational focus from a reliability and fire prevention focus. Exact steps depend on the level of fire-threat. As indicated in Table 8-12 below, “Brown”, “Red”, and “Orange” are considered elevated fire-threat conditions that require the BVES system to be configured for fire prevention over reliability concerns.

Table 8-12 Operational Direction Based on NFDRS Forecast

Operational Action	Green	Yellow	Brown	Orange	Red
Circuit Recloser Settings	Automatic Reclosing	Automatic Reclosing	Non-Automatic Reclosing	Non-Automatic Reclosing	Non-Automatic Reclosing
Patrol following circuit outage	No[1]	No[1]	Yes	Yes	Yes
TripSavers	Automatic	Automatic	Non-Automatic	Non-Automatic	Non-Automatic
Proactive De-energization (PDE)	No	No	Yes – “at risk” lines when wind gusts greater than 55 mph		

[1]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.

When a Red Flag Warning condition is declared, Field Operations will closely monitor the NFDRS Forecast and other local forecasts to determine the appropriate operational conditions to be implemented. Additionally, BVES’s weather consultant provides more detailed and frequent forecast updates. It should be noted that generally Red Flag Warning conditions are assigned to areas much larger than the BVES service area, such as the County of San Bernardino. Therefore, BVES factors in the localized conditions for its service area.

BVES does not have any rapid earth fault current limiters. BVES continues to follow development with respect to these devices to determine whether this would be a prudent investment for BVES.

8.1.8.2 Grid Response Procedures and Notifications

The electrical corporation must provide a narrative on operational procedures it uses to respond to faults, ignitions, or other issues detected on its grid that may result in a wildfire induing, at a minimum, how it:

- *Locates the issues*
- *Prioritizes the issues*
- *Notifies relevant personnel and suppression resources to respond to issues*
- *Minimizes/optimizes response times to issues*

BVES’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 to other de-energized work or to training, which it has at the ready. For example, BVES can pivot from covered wire or pole replacement work to de-energized work.

BVES's vegetation management contractor has protocols in place for high fire threat weather. For example, on "Very High" fire threat conditions, BVES will require crews, staff and contractors, to:

- 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.

As necessary, BVES can conduct work with associated fire risk by de-energizing work areas as applicable. BVES does not see reduced productivity overall with this method and has not missed a program target.

BVES will notify the Big Bear Fire Department (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.

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

The electrical corporation must provide a narrative on the following:

- *The electrical corporation's procedures that designate what type of work the electrical corporation allows (or does not allow) personnel to perform during operating conditions of different levels of wildfire risk, including:*
- *What the electrical corporation allows (or does not allow) during each level of risk*
- *How the electrical corporation defines each level of wildfire risk*
- *How the electrical corporation trains its personnel on those procedures*
- *How it notifies personnel when conditions change, warranting implementation of those procedures*
- *The electrical corporation's procedures regarding deployment of firefighting staff and equipment (e.g., fire suppression engines, hoses, water tenders, etc.) to construction and/or electrical worksites for site-specific fire prevention and ignition mitigation during on-site work*

BVES will enforce operational changes when a RFW issuance or when its weather consultant forecasts high risk conditions through local weather stations and the NFDRS reports. This initiative is critical to ensuring safe operations during routine and specialized work taking place within the service area.

During high fire threat weather, BVES suspends all work, by BVES staff or its contractors, that might produce sparks or create fire hazards. As discussed above, due to BVES's small size, BVES and its contractors are able to pivot to other low risk work during such conditions. All line crews and field personnel are trained on this fire safe protocol.

During a potential emergency or significant event, a rapid response, with specific resources can reduce the risk of the event leading to a wildfire. BVES has a Wildfire Infrastructure Protection Team (WIPT). Given the need for capabilities during wildfire incidences and other emergencies, the WIPT aligns with BVES's Emergency Response Team (ERT). Both teams consist of the Utility Manager, Field Operations Supervisor, Service Crew, and Customer Service staff.

The Utility Manager oversees the WIPT. The Field Operations Supervisor will direct field activities and operations during the emergency. The Service Crew (or Dutyman outside normal working hours) will provide initial field response to the emergency. Additional linemen will be called out as needed. Furthermore, Customer Service staff and/or additional staff may be called out to assist with notification procedures as needed. Other staff may be called out at the direction of the Utility Manager to assist, as needed. F or example, Engineering staff may be called out to assist linemen in monitoring local wind speeds.

Reports of wires sparking or smoke could lead to a wildfire. The Utility Engineer & Wildfire Mitigation Supervisor has issued operational guidelines or procedures to follow in the event BVES receives a report of potential fire such as "arcing, sparks, smoldering, smoke, or fire" or other emergency reports involving the overhead distribution system. Examples of reports could include customer, or third party reported arcing, sparking, smoke, or fire sightings. These procedures will be at the discretion of the Utility Manager and, given the event, will require prompt and decisive action to place the system in a safe condition.

8.1.9 Workforce Planning

In this section, the electrical corporation must report on qualifications and training practices regarding wildfire and PSPS mitigation for workers in the following target roles:

- *Asset inspections*
- *Grid hardening*
- *Risk event inspection*

For each of the target roles listed above, the electrical corporation must:

- *List all worker titles relevant to the target role.*
- *For each worker title, list and explain minimum qualifications, with an emphasis on qualifications relevant to wildfire and PSPS mitigation. Note if the job requirements include:*
- *Going beyond a basic knowledge of GO 95 requirements to perform relevant types of inspections or activities*
- *Being a "Qualified Electrical Worker" (QEW); if so, define what certifications, qualifications, experience, etc. are required to be a QEW for the target role for the electrical corporation*
- *Report the percentage of electrical corporation and contractor full-time employees (FTEs) in the target role, with specific job titles*
- *Report plans to improve qualifications of workers relevant to wildfire and PSPS mitigation. The electrical corporation must explain how it is developing more robust training programs which would teach electrical workers to identify hazards that could ignite wildfires*

The electrical corporation must provide details regarding training and qualifications in Appendix B as necessary.

Table 8-13 Workforce Planning, Asset Inspections

Worker Title (Employee / Contractor)	Minimum Qualifications for Target Role	Special Certification Requirements	Electrical Corporation % FTE Min Quals	Electrical Corporation % Special Certifications	Reference to Elec Corporation Training/Qualifica Programs
Field Inspector (BVES Employee)	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	Journeyman Lineman	100%	100%	
Light Crew Foreman (BVES Employee)	Three years of experience as a Journeyman Lineman or Service Crew Foreman. IBEW Journeyman Lineman status in good standing. Knowledge of: Methods, materials, and tools used in electrical overhead and underground construction, maintenance, and repair work. 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. Occupational hazards and standard safety precautions necessary in work. Class A California Driver's License.	Journeyman Lineman	100%	100%	

Service Crew Foreman (BVES Employee)	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: Methods, materials, and tools used in electrical overhead and underground construction, maintenance, and repair work. 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. Inspection program requirements of GO 165 and GO 174. Occupational hazards and standard safety precautions necessary in work. Class A California Driver's License.	Journeyman Lineman	100%	100%	
Substation Technician (BVES Employee)	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. Class C California Driver License. Sound knowledge of: Methods, materials, and tools used in electrical distribution system	N/A	100%	N/A	

	substation construction, operations, maintenance, diagnostic, and repair work. Principles of electrical theory as applied to distribution system substations and grid equipment (34.5 kV and 4.160 kV). Inspection program requirements of GO 174. SCADA and electric utility GIS systems. IEEE-SA - National Electrical Safety Codes (NESC) as they pertain to electrical distribution substations and grid equipment				
Utility Systems Specialist Inspector/Lead Inspector (Contractor)	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	100%	100%	
Geospatial Project Manager (Contractor)	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	Geospatial Information Systems Professional (GISP)	100%	100%	ASPRS Certified M Scientist, LiDAR

Geospatial Lead Analyst (Contractor)	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	N/A	100%	N/A	ASPRS Certified R Sensing Technolog
Geospatial Technician (Contractor)	Solid Understand of GIS and Remote Sensing Science Strong Attention to Detail Strong Computer Skills Work Independently	N/A	100%	N/A	

Table 8-14 Workforce Planning, Grid Hardening

Worker Title (Employee / Contractor)	Minimum Qualifications for Target Role	Special Certification Requirements	Electrical Corporation % FTE Min Quals	Electrical Corporation % Special Certifications	Reference to Electrical Corporation Training/Qualificati Programs
Utility Engineer & Wildfire Mitigation Supervisor (BVES Employee)	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.	100%	100%	

	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.				
Field Operations Supervisor (BVES Employee)	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	N/A	100%	N/A	
Regulatory Compliance Project Engineer (BVES Employee)	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,	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	50%	100%	

	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.	license within 12 months of employment at BVES, Inc. in this position.			
Project Coordinator (BVES Employee)	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	N/A	100%	N/A	
Utility Planner I (BVES Employee)	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.	N/A	100%	N/A	
Engineering Inspector	Minimum three years of experience at an Engineering Technical position or equivalent in an electric utility working the area of distribution.	N/A	100%	N/A	

	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				
Light Crew Foreman (BVES Employee)	Three years of experience as a Journeyman Lineman or Service Crew Foreman. IBEW Journeyman Lineman status in good standing. Knowledge of: Methods, materials, and tools used in electrical overhead and underground construction, maintenance, and repair work. 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. Occupational hazards and standard safety precautions necessary in work. Class A California Driver's License.	Journeyman Lineman	100%	100%	
Service Crew Foreman	Three years of experience at the journey level in construction, maintenance, and	Journeyman Lineman	100%	100%	

(BVES Employee)	repair of both overhead and underground electrical systems. IBEW Journeyman Lineman status in good standing. Knowledge of: Methods, materials, and tools used in electrical overhead and underground construction, maintenance, and repair work. 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. Inspection program requirements of GO 165 and GO 174. Occupational hazards and standard safety precautions necessary in work. Class A California Driver's License.				
Lineman (BVES Employee)	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	Journeyman Lineman	80%	100%	

	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.				
Substation Technician (BVES Employee)	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: IEEE-SA - National Electrical Safety Codes (NESC) as they pertain to electrical distribution substations and grid equipment. Methods, materials, and tools used in electrical distribution system substation construction, operations, maintenance, diagnostic, and repair work. Principles of electrical theory as applied to distribution system substations and grid equipment (34.5 kV and 4.160 kV). Inspection program requirements of GO 174. SCADA and electric utility GIS systems. Class C California Driver License.	N/A	100%	N/A	

Table 8-15 Workforce Planning, Risk Event Inspection

Worker Title (Employee / Contractor)	Minimum Qualifications for Target Role	Special Certification Requirements	Electrical Corporation % FTE Min Quals	Electrical Corporation % Special Certifications	Reference to Electrical Corporati Training/Qualificatio Programs
Utility Engineer & Wildfire Mitigation Supervisor (BVES Employee)	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.	Professional Engineer license in California required. If not held, must obtain within 2 years of employment.	100%	100%	
Field Operations Supervisor (BVES Employee)	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	N/A	100%	N/A	

	combination of experience and education required Thorough knowledge of GO 95/165 and Construction Methods				
Regulatory Compliance Project Engineer (BVES Employee)	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.	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.	50%	100%	

8.2 Vegetation Management and Inspection

8.2.1 Overview

In accordance with Public Utilities Code section 8386(c)(9), each electrical corporation's WMP must include plans for vegetation management.

In this section, the electrical corporation must identify objectives for the next 3- and 10-year periods, targets, and performance metrics related to the following vegetation management programmatic areas:

- *Vegetation inspections*
- *Vegetation and fuels management*
- *Vegetation management enterprise system*
- *Environmental compliance and permitting*
- *Quality assurance / quality control*
- *Open work orders*
- *Workforce panning*

8.2.1.1 Objectives

Each electrical corporation must summarize the objectives for its 3-year and 10-year plans for implementing and improving its vegetation management and inspections. These summaries must include the following:

- *Identification of which initiative(s) in the WMP the electrical corporation is implementing to achieve the stated objective, including Utility Initiative Tracking IDs*
- *Reference(s) to applicable codes, standards, and best practices/guidelines and an indication of whether the electrical corporation exceeds an applicable code, standard, or regulation*
- *Method of verifying achievement of each objective*
- *A completion date for when the electrical corporation will achieve the objective*
- *Reference(s) to the WMP section(s) or appendix, including page numbers, where the details of the objective(s) are documented and substantiated*

This information must be provided in Table 812 for the 3-year plan and Table 8-13 for the 10-year plan. Examples of the minimum acceptable level of information are provided below.

Table 8-16 BVES Vegetation Management Implementation Objectives (3-year plan)

Objectives for Three Years (2023-2025)	Applicable Initiative(s), Tracking ID(s)	Applicable Regulations, Codes, Standards, and Best Practices (See Notes)	BVES Exceeds the Regulatory Specification (Y/N)	Method of Verification (i.e., program)	Completion Date	Reference (Section and Page Number)
Maintain enhanced clearance specifications and evaluate effectiveness	Pole clearing, VM_7 Clearance, VM_9 Substation defensible space, VM_11	PRC 4292, GO 95, GO 165, GO 174	Y	Detailed, Ground, Patrol, LiDAR, UAV Inspection Programs	31-Dec-25	
Continue to proactively remove/remediate high-risk species.	High-risk species, VM_12	GO 95, ESRB-4	Y	Detailed, Ground, Patrol, LiDAR, UAV Inspection Programs	31-Dec-25	
Continue robust vegetation inspection routine of annual Detailed Inspections, Patrol Inspections, LiDAR surveys, UAV HD Photography, 3rd party Ground Patrols, and Substation Inspections	Vegetation inspections, VM-1, VM-2, VM-3, VM-4, VM-5, VM-6, VM-11	GO 95, GO 165, PRC 4292	Y	QA/QC Checks	31-Dec-25	
Implement robust vegetation management and inspection enterprise system. Ensure all trees within right of way tracked in data system.	Vegetation management enterprise system, VM_15				31-Dec-23	

Improve quality assurance and quality control program on vegetation management inspection and clearance work and asset inspection.	Quality assurance/quality control, VM_16				31-Dec-23	
Develop and implement program to promote vegetation communities that are sustainable, fire-resilient, and compatible with the use of the land as an electrical corporation right-of-way.	Fire-resilient rights-of-way, VM_13				31-Dec-25	

Table 8-17 Vegetation Management Implementation Objectives (10-year plan)

Objectives for Ten Years (2026-2032)	Applicable Initiative(s), Tracking ID(s)	Applicable Regulations, Codes, Standards, and Best Practices (See Notes)	BVES Exceeds the Regulatory Specification (Y/N)	Method of Verification (i.e., program)	Completion Date	Reference (Section and Page Number)
Continue to conduct program to promote vegetation communities that are sustainable, fire-resilient, and compatible with the use of the land as an electrical corporation right-of-way.	Fire-resilient rights-of-way, VM_13					

Evolve vegetation inspection cycles to be risk based	Vegetation inspections, VM-1, VM-2, VM-3, VM-4, VM-5, VM-6, VM-11	PRC 4292, GO 95, GO 165, GO 174	Y			
Evolve vegetation clearance cycles to be risk based	Pole clearing, VM_7 Clearance, VM_9 Substation defensible space, VM_11	GO 95, GO 165, GO 174	Y	Detailed, Ground, Patrol, LiDAR, UAV Inspection Programs		

Table 8-18 Comparison of Bear Valley's Vegetation Standards to GO 95 Minimum Requirements

Comparison of Bear Valley's Vegetation Standards to GO 95 Minimum Requirements	
Bear Valley Requirement In Excess of GO 95	**GO 95/GO 165 Requirements**
Minimum radial clearance of 72 inches between high voltage bare conductors and vegetation. (Bear Valley's bare conductors operate between 2.4kV and 72kV.)	GO 95: Minimum radial clearance of 48 inches.
No vertical coverage is allowed above sub-transmission lines (34.5kV).	GO 95: Minimum radial clearance of 48 inches.

Tree Trunk and Major Limb Exception: At the primary conductor level, mature tree trunks greater than 12 inches in diameter and major limbs greater than 12 inches in diameter with sufficient strength and rigidity may encroach within the minimum safe distance (72-inches) but not within 12 inches of the bare line conductors. The rigidity of the tree trunk or major limb must be such that it would be impossible for it to encroach within 12 inches of the bare conductor at any time during high wind, heavy icing and snow, or other conditions. Must satisfy Tree Trunk and Major Limb Exception flowchart in Bear Valley's Vegetation Management and Vegetation QA/QC Programs.	GO 95: Mature trees whose trunks and major limbs are located more than six inches, but less than the clearance required by Table 1, Cases 13E and 14E, from primary distribution conductors are exempt from the minimum clearance requirement under this rule. The trunks and limbs to which this exemption applies shall only be those of sufficient strength and rigidity to prevent the trunk or limb from encroaching upon the six–inch minimum clearance under reasonably foreseeable local wind and weather conditions.
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.	GO 95: Minimum radial clearance of 48 inches.
Dead, rotten, or diseased trees or dead, rotten, or diseased portions of otherwise healthy trees overhang or lean toward and may fall into a span of power lines, said trees or portions thereof must be removed. Note that this may apply to trees outside the clearance zone.	GO 95: Minimum radial clearance of 48 inches.
BVES conducts two patrol inspections per year. One is conducted by BVES's qualified Field Inspector. The other is conducted by a qualified contractor experience in power line inspections and is referred to as "Third Party Ground Patrol" (Initiatives 7.3.5.9 and 7.3.5.11)."	GO-165: Patrol inspections in rural areas shall be increased to once per year in Tier 2 and Tier 3 of the High Fire-Threat District.
BVES conducts one LiDAR survey per year of its entire overhead system. (Initiative 7.3.5.7)	GO 95/GO 165: No LiDAR inspection requirement in GO 95 or GO 165.

BVES conducts one aerial HD photography/videography survey per year of its entire overhead system. (Initiative 7.3.5.9)	GO 95/GO 165: No LiDAR inspection requirement in GO 95 or GO 165.

8.2.1.2 Targets

Initiative targets are quantifiable measurements of activities identified in the WMP. Electrical corporations will show progress towards completing targets in subsequent reports, including QDRs and WMP Updates.

The electrical corporation must list all targets it will use to track progress on its vegetation management and inspections for the three years of the Base WMP. Energy Safety's Compliance Assurance Division and third parties must be able to track and audit each target.25 For each initiative target, the electrical corporation must provide the following:

- *Utility Initiative Tracking IDs*
- *Projected targets for each of the three years of the Base WMP and relevant units*
- *Quarterly, rolling targets for end of 2023 and 2024 (inspections only)*
- *For 2023–2025, the "x% risk impact" For each of the three years of the Base WMP. The expected x% risk impact is the expected percentage risk reduction per year, as described in a7.2.2.2*
- *Method of verifying target completion*

The electrical corporation's targets must provide enough detail to effectively inform efforts to improve the performance (i.e., reduction in ignition probability or wildfire consequence) of the electrical corporation's vegetation management and inspections initiatives.

Table 8-19 Vegetation Management Initiative Targets by Year

Initiative Activity	Tracking ID	Units	2023 Target	X% Risk Impact 2023	2024 Target	X% Risk Impact 2024	2025 Target	X% Risk Impact 2025	Method of Verification
Pole clearing	VM_7	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Wood and slash management	VM_8	Contractor Adhered to Waste Removal	Waste Removal Requirements Met		Waste Removal Requirements Met		Waste Removal Requirements Met		Contract Status
Clearance	VM_9	Circuit Miles Cleared	72		72		72		Quantitative
Fall-in mitigation	VM_10	Number of trees remediated or removed to prevent fall-in	88		88		88		Quantitative
Substation defensible space	VM_11	Substations inspected and cleared	13		13		13		Quantitative
High-risk species	VM_12	WMP Plan Review and Vegetation Discussion with Experts	WMP Plan Review and Vegetation Discussion with Experts		WMP Plan Review and Vegetation Discussion with Experts		WMP Plan Review and Vegetation Discussion with Experts		Version History
Fire-resilient rights-of-way	VM_13	WMP Plan Review and Vegetation	WMP Plan Review and Vegetation		WMP Plan Review and Vegetation		WMP Plan Review and Vegetation		Version History

		Discussion with Experts	Discussion with Experts		Discussion with Experts		Discussion with Experts		
Emergency response vegetation management	VM_14	Verification of Readiness and Review of Plan	Verification of Readiness and Review of Plan		Verification of Readiness and Review of Plan		Verification of Readiness and Review of Plan		Version History
Vegetation management enterprise system	VM_15	Ongoing Monitoring and Maintenance	100%		100%		100%		Budget Review
Quality assurance / quality control	VM_16	Number of Vegetation QCs	72		72		72		Quantitative
Open work orders	VM_17	No discrepancy exceeding GO95 resolution timeframes	All WO resolved within GO 95 Timeframe		All WO resolved within GO 95 Timeframe		All WO resolved within GO 95 Timeframe		WO Log
Workforce planning	VM_18	Verify Appropriate Staffing Levels for Wildfire Related Activities	Staffing Level Verified		Staffing Level Verified		Staffing Level Verified		Meeting Minutes

Table 8-20 Vegetation Inspections Targets by Year

Initiative Activity	Tracking ID	Units	Target End of	Target End	End of Year	X% Risk	Target End	Target End	End of Year	X% Risk	Target 2025	X% Risk	Method of Verification

			Q2 2023	of Q3 2023	Target 2023	Impact 2023	of Q2 2024	of Q3 2024	Target 2024	Impact 2024		Impact 2025	
Vegetation inspections	VM_1	Circuit Miles Inspected	60	100	134		0	*40*	*51*		*53*		Quantitative
Vegetation inspections	VM_2	Circuit Miles Inspected	0	211	211		0	211	211		211		Quantitative
Vegetation inspections	VM_3	Circuit Miles Inspected	0	211	211		0	211	211		211		Quantitative
Vegetation inspections	VM_4	Circuit Miles Inspected	0	211	211		0	211	211		211		Quantitative
Vegetation inspections	VM_5	Circuit Miles Inspected	0	211	211		0	211	211		211		Quantitative
Vegetation inspections	VM_6	Circuit Miles Inspected	0	211	211		0	211	211		211		Quantitative

8.2.1.3 Performance Metrics Identified by BVES

Performance metrics indicate the extent to which an electrical corporation's Wildfire Mitigation Plan is driving performance outcomes. The electrical corporation must:

- *List the performance metrics the electrical corporation uses to evaluate the effectiveness of its vegetation management and inspections in reducing wildfire and PSPS risk*

For each of these performance metrics listed, the electrical corporation must:

- *Report the electrical corporation's performance since 2020 (if previously collected)*
- *Project performance for 2023-2025*
- *List method of verification*

The electrical corporation must ensure that each metric's name and values are the same in its WMP reporting as its QDR reporting (specifically, QDR Table 2 and QDR Table 3). Metrics listed in this section that are the same as performance metrics required by Energy Safety and reported in QDR Table 2 (Performance Metrics)29 must match those reported in QDR Table 2. Metrics listed in this section that are not the same as any of the performance metrics identified by Energy Safety and reported in QDR Table 2 must match those reported in QDR Table 3.

The electrical corporation must:

- *Summarize its self-identified performance metric(s) in tabular form*
- *Provide a brief narrative that explains trends in the metrics*

Table 8-21 provides a list of performance metrics that relate to BVES Vegetation management and Inspection program. Many of these metrics are used as tracking (tree's trimmed, tree removal, tree attachments removed, Circuit Miles Trimmed, QC's, and Customer Service calls) for annual performance. These metrics show annual accomplishment and are not intended to be trend based, but they do however have an affect on Vegetation Ignitions, Vegetation caused outage, and Vegetation inspection findings. As you can see in the table below those that are directly affected by the annual tracking metrics are trending down or remaining the same year over year.

Table 8-21 Vegetation Management and Inspection Performance Metrics Results by Year

Performance Metrics	2020	2021	2022	2023 Projected	2024 Projected	2025 Projected	Method of Verification (e.g., third-party evaluation, QDR)
Vegetation-caused ignitions	0	0	0	0	0	0	QDR Table 2
Vegetation-caused outages	5	6	19	10	10	10	QDR Table 2

Vegetation Inspection Findings (All Methods)	N/A	520	375	145	145	145	QDR Table 2
Tree Attachment Removal	N/A	N/A	83	100	100	100	QDR Table 3
Tree's Trimmed	N/A	N/A	6042	N/A	N/A	N/A	QDR Table 3
Tree Removal	N/A	N/A	147	N/A	N/A	N/A	QDR Table 3
Circuit Miles Trimmed	N/A	N/A	86.84	72	72	72	QDR Table 3
VM QC's	N/A	N/A	132	72	72	72	QDR Table 3
Number of Customer Service calls about Tree Trimming	N/A	N/A	87	100	100	100	QDR Table 3

This initiative includes identifying and addressing deficiencies in inspections protocols, practices, and implementation by improving training and the evaluation of inspectors the identification and actionable outcomes of deficiencies and inspection protocols executed in the field. VM Inspection Improvement actions also support improvement of training and applying lessons learned from third party contractor services and inspections. Additionally, it 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.

BVES maintains routine training and assessment of vegetation management practices. BVES also applies annual lessons learned or identified improvements and tracks developing inspection practices in the industry. BVES conducts quarterly vegetation management assessments, and an annual audit of the vegetation management programs to identify and develop areas for improvements.

BVES performs inspection improvement activities across all of its inspections. Inspection techniques for the various inspections BVES performs do not vary significantly. Therefore, not much risk reduction is gained by prioritizing improvement of inspections in higher risk areas over lower risk areas – the same inspections are performed across the service territory.

BVES does prioritize implementing lessons learned and inspection improvements in its high-risk areas and prior to the fire season Santa Ana wind period.

8.2.2 Vegetation Inspections

In this section, the electrical corporation must provide an overview of its procedures for vegetation management inspections.

The electrical corporation must first summarize details regarding its vegetation management inspections in Table 8-17. The table must include the following:

- *Type of inspection: distribution, transmission, substation, etc.*
- *Inspection program name: Identify various inspection programs within the electrical corporation (e.g., routine, enhanced vegetation, high-risk species, and off-cycle)*
- *Frequency or trigger: Identify the frequency or triggers, such as inputs from the risk model. Indicate differences in frequency or trigger by HTFD Tier, if applicable*
- *Method of inspection: Identify the methods used to perform the inspection (e.g., patrol, detailed, sounding or root examination, aerial, and LiDAR)*
- *Governing standards and operating procedures: Identify the regulatory requirements and the electrical corporation's procedures for addressing them*

Table 8-22 Exemplar Vegetation Management Inspection Frequency, Method, and Criteria

Type	Inspection Program	Frequency or Trigger (Note 1)	Method of Inspection (Note 2)	Governing Standards & Operating Procedures
Distribution	Detailed Inspection	5 Years	Detailed	GO 165 & GO 95 (Rule 18)
Distribution	Patrol Inspection	Annual	Patrol	GO 165 & GO 95 (Rule 18)
Distribution	UAV HD Photography/Videography	Annual	Arial	GO 165
Distribution	LiDAR Inspection	Annual	LiDAR	GO 95 (Rule 18)
Distribution	3rd Part Ground Patrol	Annual	Patrol	GO 165 & GO 95
Substation	Substation Inspection	Monthly	Detailed	GO 174

Note 1: The electrical corporation must provide electrical corporation-specific risk-informed triggers used for vegetation management.

Note 2: The electrical corporation must provide electrical corporation-specific definitions of the different methods of inspection.

The electrical corporation must then provide a narrative overview of each vegetation inspection program identified in the above table; Sections 8.2.2.1. provides instructions for the overviews. The sections should be numbered 8.2.2.1 to Section 8.2.2.n (i.e., each vegetation inspection program is detailed in its own section). The electrical corporation must include inspection programs it is discontinuing or has discontinued since the last WMP submission; in these cases, the electrical corporation must explain why the program is being discontinued or has been discontinued.

8.2.2.1 Detailed Inspection

Process

The BVES Inspection Plan is intended to promote safety, circuit reliability, minimal service interruption, and reduced risk of fire through routine visual inspection of facility conditions. The inspection focus is ensuring compliance to G.O. 95 and G.O. 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 G.O. 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 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.

Frequency or trigger

BVES conducts these inspections at least once every five years in compliance with GO 165 and GO 95 (Rule 18). If any defects outlined above are identified, BVES prioritizes the defect resolution based on risk and resolves the issues in compliance with GO 95 Rule 18 timeframes. BVES divides its system up and each year conducts a number of Detailed Inspections such that each circuit is Detailed Inspected at least every five years.

Accomplishments, roadblocks, and updates

In this section, the electrical corporation must discuss:

- *Noteworthy accomplishments for the inspection program since the last WMP*

- *Roadblocks the electrical corporation has encountered while implementing the inspection program and how the electrical corporation has addressed the roadblock*
- *Changes/updates to inspection program since the last WMP Including known future plans (beyond the current year) and new/novel strategies the electrical corporation may implement in the next 5 years (e.g., references to and strategies from pilot projects and research)*

8.2.2.2 Patrol Inspection

Process

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 Detailed Inspections are cross checked against other vegetation inspections to evaluate the quality and effectiveness of each inspection type.

Frequency or trigger

Circuit Patrol will be performed on a circuit-by-circuit basis at least once per year directed by G.O. 165. BVES has an emergency response plan in effect that prioritizes circuits serving key public agencies such as hospitals, emergency response services, etc. Circuits will be patrolled in order of priority to ensure public safety and reliability.

8.2.2.3 UAV HD Photography/Videography Inspection

Process

BVES conducts an annual UAV HD Photography/Videography inspection. This initiative is a high definition (HD) imagery aerial survey of BVES’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 will allow BVES to verify, document and resolve vegetation encroachment and overheating and degrading equipment issues before they make contact with bare conductors.

Frequency or trigger

BVES performs a UAV HD Photography/Videography survey of all of its circuits each year. It takes an expert contractor approximately six weeks to conduct the inspection and document the findings of the entire BVES system (211 circuit miles of overhead facilities and power lines). BVES does prioritize completing the UAV HD Photography/Videography Survey prior to the fire season Santa Ana wind period.

8.2.2.4 LiDAR Inspection

Process

BVES conducts one LiDAR sweep per year to evaluate the effectiveness of clearance efforts and identify potential wildfire hazards. This is an enhanced inspection using LiDAR (Light Detection and Ranging) inspections and analysis, 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. BVES 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 BVES's electrical system to the road network and the tree canopy that is typical of distribution systems, truck-mounted mobile LiDAR will be utilized more often because it is 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 (211 circuit miles of overhead facilities and power lines).

Accomplishments, roadblocks, and updates

8.2.2.5 3rd Party Ground Patrol Inspection

Process

BVES conducts an annual 3rd Party Ground Patrol Inspection. This inspection is 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 BVES's Field Inspector performs as described in **Section 8.2.2.2**. 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 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 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

Frequency or trigger

BVES performs a 3rd Party Ground Patrol Inspection of all its circuits each year. It takes its expert contractor approximately three weeks to conduct the inspection and document the findings of the entire BVES system. BVES prioritizes completing the 3rd Party Ground Patrol Inspection prior to the fire season Santa Ana wind period.

8.2.2.6 Substation Inspection

Process

Monthly inspections of the BVES substations in compliance with the State of California G.O. 174 recommendations. The inspection will include 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. Any sign of growth or encroachment that does not meet GO 174 will be removed.

Frequency or trigger

BVES conducts monthly inspections of all substations in the service territory. As security cameras are installed and connected to SCADA at the substation, visual inspection via feed could act as a trigger for vegetation management action. These cameras have not yet been installed and connected to SCADA.

Accomplishments, roadblocks, and updates

In this section, the electrical corporation must discuss:

- *Noteworthy accomplishments for the inspection program since the last WMP*
- *Roadblocks the electrical corporation has encountered while implementing the inspection program and how the electrical corporation has addressed the roadblock*
- *Changes/updates to inspection program since the last WMP Including known future plans (beyond the current year) and new/novel strategies the electrical corporation may implement in the next 5 years (e.g., references to and strategies from pilot projects and research)*

8.2.3 Vegetation and Fuels Management

In this section, the electrical corporation must discuss the following mitigation initiatives associated with vegetation and fuel management:

1. *Fuels management*
2. *Clearance*
3. *Fall-in mitigation*
4. *Substation defensible space*
5. *High-risk species*
6. *Fire-wise right-of-way*
7. *Emergency response vegetation management*

In the following subsections, the electrical corporation must provide an overview of its vegetation and fuels management initiatives. These overviews should include figure(s) that depict the workflow and decision process used for vegetation and fuels management. Figure 8-3 provides an example of the appropriate level of detail for tree trimming and removal.

In addition to figure(s), the electrical corporation must provide a narrative overview of each vegetation and fuels management initiative. The discussion must include the following:

- *Utility Initiative Tracking ID.*
- *Overview of the initiative: A brief description of the initiative including reference to related objectives and targets*
- *Governing standards and electrical corporation standard operating procedures: Reference to the appropriate code and electrical corporation procedure. If any standard exceeds regulatory requirements, the electrical corporation must reference the document that the electrical corporation uses as a basis for exceeding the regulatory requirements.*
- *Updates to the initiative: Changes to the initiative since the last WMP submission and a brief explanation as to why those change were made. Discuss any planned improvements or updates to the initiative and the timeline for implementation.*

8.2.3.1 Pole Clearing (VM_7)

In this subsection, the electrical corporation must provide an overview of fuel management activities, including:

- *Pole clearing per Public Resources Code section 4292*
- *Pole clearing outside the requirements of Public Resources Code section 4292 (e.g., pole clearing performed outside of the State Responsibility Area)*

BVES has a vegetation management plan in place that meets or exceeds the PRC 4292. 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 come into contact with 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, where possible. With the complete replacement of its traditional overhead expulsive fuses, nearly all of BVES's poles are now exempt from PRC 4292.

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 USFS. 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.

8.2.3.2 Wood Slash Management (VM_8)

In this subsection, the electrical corporation must provide an overview of how it manages all downed wood and "slash" generated from vegetation management activities, including references to applicable regulations, codes, and standards.

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.

Fuels reduction is a key element to wildfire mitigation. BVES'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. BVES also collaborates with the US Forest Service to remove trees near lines and removes the slash as agreed upon by the local US Forest Ranger.

BVES will continue to evaluate the effectiveness of its Wood Slash Management Program and make updates as needed.

8.2.3.3 Clearance (VM_9)

In this subsection, the electrical corporation must provide an overview of clearance activities, including:

- *Clearances established more than the minimum clearances in Table 1 of GO 95*
- *The bases for the clearances established*

BVES has a vegetation management plan in place that meets or exceeds the minimum requirements of the CPUC's applicable GOs. 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 USFS. 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.

The BVES vegetation management contract also contains many 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. The utility-defined specifications comply with or exceed those outlined in GO 95, Rules for Overhead Electric Line Construction, Rule 35 Vegetation management, and Appendix E Guidelines to Rule 35 and Commission Decisions, such as D.17-12-024. As previously described, BVES has unique local conditions that require it, in certain circumstances, to go beyond the regulated vegetation clearance standards. These enhanced specifications include:

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. 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), based upon species, growth rate, site characteristics.

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. Take the following action:

- 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 will be tracked in BVES’s tree tracking program.

8.2.3.4 Fall-in Mitigation (VM_10)

In this subsection, the electrical corporation must provide an overview of its actions taken to remove or otherwise remediate trees that pose a high risk of failure or fracture that could potentially strike electrical equipment (e.g., danger trees or hazard trees).

BVES has a vegetation management plan in place that meets or exceeds the CPUC’s applicable GOs. 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. 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 USFS. 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 adheres to specifications, detailed above (e.g., clearances in Section 8.2.3.3) and immediately below.

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).

8.2.3.5 Substation Defensible Space (VM_11)

In this subsection, the electrical corporation must provide an overview of its actions taken to reduce the ignition probability and wildfire consequence due to contact with substation equipment.

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 the 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.

8.2.3.6 High-Risk Species (VM_12)

In this subsection, the electrical corporation must provide an overview of its actions, such as trimming, removal, and replacement, taken to reduce the ignition probability and wildfire consequence attributable to high-risk species of vegetation.

BVES has a vegetation management plan in place that meets or exceeds the minimum requirements of the CPUC's applicable GOs. 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 USFS. 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.

BVES will 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 (note: due to its elevation and climate, BVES does not have palm or eucalyptus trees present). All such trees will be trimmed to at least 12 feet minimum (or more if warranted) and evaluated for removal in each case. BVES's contractor may determine that additional clearance would be prudent based on growth factors, wind, ice, etc. This information will be tracked in BVES's tree tracking program.

8.2.3.7 Fire-Resilient Right-of-Ways (VM_13)

In this subsection, the electrical corporation must provide an overview of its actions taken to promote vegetation communities that are sustainable, fire-resilient, and compatible with the use of the land as an electrical corporation right-of-way. It must also provide an overview of its actions to control vegetation that is incompatible with electrical equipment and with the use of the land as an electrical corporation right-of-way. This may include, but is not limited to, the following activities: the strategic use of herbicides, growth regulators, or other chemical controls; tree-replacement programs; promotion of native shrubs; prescribed fire; or fuel treatment activities not covered by another initiative.

BVES has a vegetation management plan in place that meets or exceeds the applicable minimum requirements of the CPUC's GOs. 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 come into contact with 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 USFS. 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.

Right of Way: All brush, limbs and foliage in the 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 removed 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.

8.2.3.8 Emergency Response Vegetation Management

In this subsection, the electrical corporation must provide an overview of the following emergency response vegetation management activities:

- *Activities based on weather conditions:*
- *Planning and execution of vegetation management activities, such as trimming or removal, executed based on and in advance of a Red Flag Warning or other weather condition forecast that indicates an elevated fire threat in terms of ignition probability and wildfire potential.*
- *Post-fire service restoration:*
- *Vegetation management activities during post-fire service restoration, including, but not limited to, activities or protocols that differentiate post-fire vegetation management from programs described in other WMP initiatives; supporting documentation for the tool and/or standard the electrical corporation uses to assess the risk presented by vegetation after a fire; and how the electrical corporation includes fire-specific damage attributes in its assessment tool/standard. The description of such activities must differentiate between those emergency actions initiated to restore power while active fire suppression is ongoing and actions that occur following active fire suppression during the post-fire suppression repair and rehabilitation phases of fire protection operations.*

BVES has a vegetation management plan in place that meets or exceeds the minimum requirements of the CPUC's applicable GOs. 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 come into contact with 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 USFS. 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.

Emergency Vegetation Clearance: This scope of work includes completing maintenance on an as-needed basis for any major disaster or emergency events. For example, if a storm results in fallen trees and branches, the contractor must mobilize as soon as possible to clear the vegetation.

While BVES has not experienced a significant fire, it remains prepared to respond quickly in the even an ignition source impacts adjacent vegetation or threatens public access. 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.

8.2.4 Vegetation Management Enterprise System

In this section, the electrical corporation must provide an overview of inputs to, operation of, and support for a centralized vegetation management enterprise system updated based upon inspection results and management activities such as trimming and removal of vegetation. This overview must include discussion of:

- *The electrical corporation's vegetation inventory and condition database(s)*
- *Describe the utilities internal documentation of its database(s)*
- *Integration with systems in other lines of business*
- *Integration with the auditing system(s) (see Section 8.2.5, "Quality Assurance and Quality Control").*
- *Describe internal processes for updating enterprise system including database(s) and any planned updates*
- *Any changes to the initiative since the last WMP submission and a brief explanation as the why those changes were made. Include any planned improvements or updates to the initiative and timeline for implementation*

BVES is implementing a new vegetation management enterprise system in 2023 created specifically to meet BVES needs. The program is called "iRestore Tree Action Inventory Application." This application allows BVES to catalog every tree within the service territory and document a list of data of each tree. The database will include information on 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 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 database through iPads and mobile phones to document all the above inputs on all work completed. BVES pre-inspectors also have access to the database and enter all inspections into the database. The information from iRestore is also migrated into BVES's GIS database. In the next update of the application, QA/QC reviews and information will be integrated into the application. Once completed, iRestore will have QA/QC integrated into the application. As a new application, BVES expects iRestore will require frequent updates to create a better inventory system usable and visible by all necessary BVES staff.

Data Source	Storage Location	Planned Next Steps	Storage Type (Excel, GIS, etc.)
Vegetation Management	Partners & Spreadsheet Database	Migration to iRestore (cloud-based) software Oct. 2022	Excel, Geo Database

The iRestore tree 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. The software will provide alerts on trees that require revisiting based on growth rates. Additionally, the software will alert when a tree is about to exceed its review time based on the cycle schedule. This database is expected to be fully up and running by the end of 2023. BVES is also considering tagging trees with tags that electronically connect with mobile devices that crews and inspectors would use to enhance accuracy of data recording.

8.2.5 Quality Assurance / Quality Control (QA/QC)

In this section, the electrical corporation must provide an outline of its quality assurance and quality control (QA/QC) activities for vegetation management. This overview must include:

- *Reference to procedures documenting QA/QC activities.*
- *How the sample sizes are determined and how the electrical corporation ensures the samples are representative.*
- *Who performs QA/QC (internal or external, is there a dedicated team, etc.).*
- *Qualifications of the auditors.*
- *Documentation of findings and how the lessons learned from those findings are incorporated into trainings and/or procedures.*
- *Any changes to the procedures since the last WMP submission and a brief explanation as to why those changes were made. Include any planned improvements or updates to the initiative and the timeline for implementation.*
- *Tabular information:*
- *Sample sizes*
- *Type of QA/QC performed (e.g., desktop or field)*

- *Resulting pass rates, starting in 2022*
- *Yearly target pass rate for the 2023-2025 Base WMP cycle*

Table 8-18 provides an example of the appropriate level of detail.

Table 8-23 Vegetation Management QA/QC Program

Activity Being Audited	*Sample* **Size**	Type of Audit	Audit Results 2022	Yearly Target Pass Rate for 2023-2025
Tree Trimming by contractor	132 inspections completed in 2022 (1,419 Trees)	Verify Contractor's Tree Trimming meets standards	Completed (99% pass rate for trees inspected)	99%

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.

Quality Assurance

In 2023, BVES aims to improve vegetation management inspection by conducting QA assessments and audits per BVES QA/QC procedures. In 2022, 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 included 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 table below, VM Program Annual QA Audit Areas.

Table 8-24 VM Program Annual QA Audit Areas

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 program 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.) conducted in accordance with the Company's effective Wildfire Mitigation Plan?
	Are the results of VM inspections documented, tracked, and resolved in a timely manner in accordance with GO-95 Rule 18?
	For each type of inspection performed, assess whether 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 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 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 or periodicity of the VM Quarterly Reports?
VM Program	Overall, are 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?

Quality Control

In 2022, BVES aims to continue to execute vegetation management QC per its vegetation management QC procedures. In 2022, BVES set a QC target to conduct 72 QC reviews. QC reviews are to be conducted by qualified staff designated in the BVES vegetation management procedures manual. Quarterly audits will be conducted by the Wildfire Mitigation and Reliability Engineer, and the annual program audit by the contracted Forester.

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 assigned QC area. The assigned staff then go to the assigned area and 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' Partner Software (part of BVES' GIS suite). Discrepancies are designated and corrected as follows:

1. Emergency (Priority 1) vegetation orders will be corrected immediately (or mitigated to reduce the priority level to at least Priority 2).

1. Urgent (Priority 2) vegetation orders will be corrected within 30 days.

2. Routine (Priority 3) vegetation orders will document non urgent items that will be addressed during the regular tree trimming cycle.

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 recordkeeping 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.

BVES will monitor the results of its vegetation management QA/QC programs and implement improvements as warranted. 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.

8.2.6 Open Work Orders

In this section, the electrical corporation must provide an overview of the process it uses to manage its open work orders. This overview must include a brief narrative that provides:

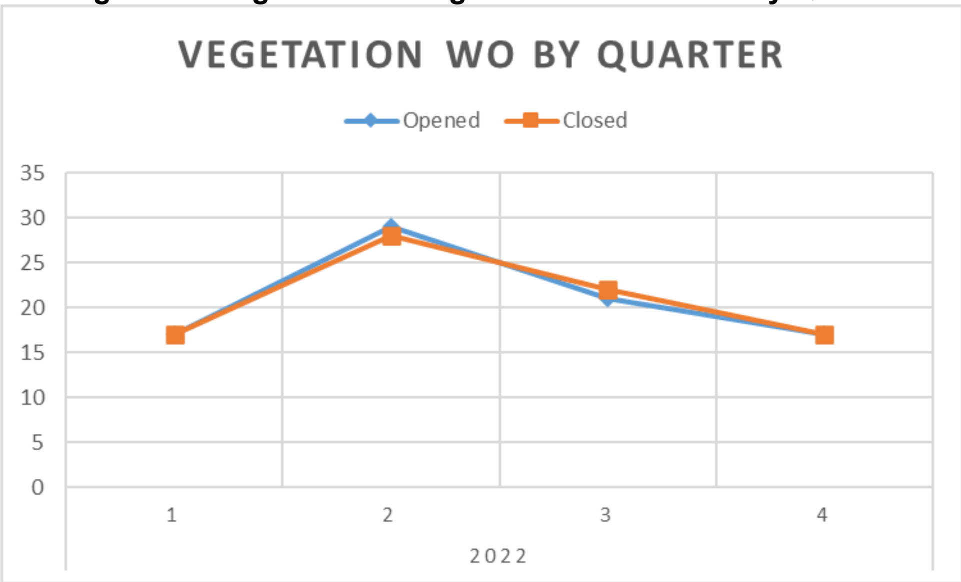
- *Reference to procedures/programs documenting the work order process.*
- *Process for prioritization of work orders based on risk*
- *Process for eliminating a backlog of work orders (i.e., open work orders that have passed remediation deadlines), if applicable*
- *A discussion of trends with respect to open work orders*

In addition, each electrical corporation must graph open work orders over time as reported in the QDRs.

Table 8-25 Number of Past Due VM Work Orders Categorized by Age

HFTD 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

Figure 8-3 Vegetation Management Work Orders By Quarter



All open tasks and work orders will be tracked in iRestore. Additionally, all inspection findings will generate a new work order which will also be tracked in iRestore. BVES began this effort in Q1 2023.

8.2.7 Workforce Planning

In this section, the electrical corporation must provide a brief overview of its recruiting practices for vegetation management personnel. It must also provide its worker qualifications and training practices for workers in the following target roles:

- *Vegetation inspections*
- *Vegetation management projects*

For each of the target roles listed above, the electrical corporation must:

- *List all worker titles relevant to the target role.*
- *List and explain minimum qualifications for each worker title with an emphasis on qualifications relevant to vegetation management. Note if the job requirements include the following:*

- *Special certification requirements, such as being an International Society of Arboriculture Certified Arborist with specialty certification as a Utility Specialist or a California-licensed Registered Professional Forester*
- *Additional training on biological resources identification and protection (e.g., plant and animal species and habitats); and cultural prehistoric and historic resources identification and protection*
- *Report the percentage of electrical corporation and contractor full-time equivalents (FTEs) in target roles with specific job titles.*

Table 8-26 Vegetation Management Qualifications and Training

Worker Type	Minimum Qualifications for Target Role	Special Certification Requirements	Electrical Corporation % FTE Min Quals	Electrical Corporation % Special Certifications	Contractor % FTE Min Quals	Contractor % Special Certifications	Reference to Electrical Corporation Training/Qualificatio Programs Improvements
Utility Engineer & Wildfire Mitigation Supervisor (BVES Employee)	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.	Professional Engineer license in California required. If not held, must obtain within 2 years of employment.	100%	100%	*N/A*	*N/A*	None required

	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.						
Wildfire Mitigation and Reliability	Bachelor of Science degree in	N/A	100%	100%	*N/A*	*N/A*	None required

Engineer (BVES Employee)	Engineering, Mathematics, Physics, or other related technical discipline. Prior electric utility experience preferred. Understanding of statistical analysis and probabilistic methods preferred. Prior experience working with Enterprise Resource Planning (ERP) software or asset management software, Oracle based accounting systems, Outage Management Systems, Geographic Information Systems (GIS) and SCADA systems preferred.						

Field Inspector (BVES Employee)	Three years of Journeyman Lineman or above experience. Experience inspecting overhead and underground facilities. Class C California Driver's License	IBEW Journeyman Lineman status in good standing Demonstrated knowledge and proficiency in GO 95, GO 128, and GO 165 requirements.	100%	100%	*N/A*	*N/A*	None required
Utility Systems Specialist Inspector/Lead Inspector (Contractor)	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	*N/A*	*N/A*	100%	100%	None required

Geospatial Project Manager (Contractor)	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	Geospatial Information Systems Professional (GISP)	*N/A*	*N/A*	100%	100%	ASPRS Certified Mapping Scientist, LiDAR
Geospatial Lead Analyst (Contractor)	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	N/A	*N/A*	*N/A*	100%	N/A	ASPRS Certified Remote Sensing Technologist
Geospatial Technician (Contractor)	Solid Understand of GIS and Remote	N/A	*N/A*	*N/A*	100%	N/A	None required

	Sensing Science Strong Attention to Detail Strong Computer Skills Work Independently						
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	ISA Certification Line-clearance qualified tree-trimmer	*N/A*	*N/A*	100%	100%	None required
Tree Trimmer (Contractor)	Strong work ethic Current California Driver License (Class B permit) General computer skills	ISA Certification Line-clearance qualified tree-trimmer	*N/A*	*N/A*	100%	100%	None required

8.3 Situational Awareness and Forecasting

8.3.1 Overview

In this section, the electrical corporation must identify objectives for the next 3- and 10-year periods, targets, and performance metrics related to the following situational awareness and forecasting programmatic areas:

- *Environmental monitoring systems*
- *Grid monitoring systems*
- *Ignition detection and alarm systems*
- *Weather forecasting*
- *Ignition likelihood calculation*
- *Ignition consequence calculation*

8.3.1.1 Objectives

Each electrical corporation must summarize the objectives for its 3-year and 10-year plans for implementing and improving its situational awareness and forecasting. These summaries must include the following:

- *Identification of which initiative(s) in the WMP the electrical corporation is implementing to achieve the stated objective, including Utility Initiative Tracking IDs*
- *Reference(s) to applicable codes, standards, and best practices/guidelines and an indication of whether the electrical corporation exceeds an applicable code, standard, or regulation*
- *Method of verifying achievement of each objective*
- *A completion date for when the electrical corporation will achieve the objective*
- *Reference(s) to the WMP section(s) or appendix, including page numbers, where the details of the objective(s) are documented and substantiated*

This information must be provided in Table 8-19 for the 3-year plan and Table 8-20 for the 10-year plan. Exemplars of the minimum acceptable level of information are provided below.

Table 8-27 Situational Awareness Initiative Objectives (3-year plan)

Objectives for Three Years (2023-2025)	Applicable Initiative(s), Tracking ID(s)	Applicable Regulations, Codes, Standards, and Best Practices (See Notes)	Method of Verification (i.e., program)	Completion Date	Reference (Section and Page Number)
Complete online diagnostic pilot	Grid monitoring systems, SAF_3		Completion of Pilot. Internal review of results	31-Dec-23	Section 8.1.2.8

program and evaluate effectivenes s.					
Complete installation of fault indicators (FIs). Evaluate need for additional (FIs)	Grid monitoring systems, SAF_2		Close of work order. Internal review of cost-benefit	31-Dec-23	Section 8.3.3.3
Evaluate need for additional weather stations.	Environmental monitoring systems, SAF_1		N/A	31-Dec-25	Section 8.3.1
Evaluate need for additional HD Alert Cameras.	Ignition detection systems, SAF_4		N/A	31-Dec-25	Section 8.3.1
Develop and implement Fire Potential Index.	Fire potential index, SAF_6		FPI Tool – Technosylva?	31-Dec-23	Section 7
Improve staff proficiency in utilizing advanced fire threat weather forecasting tools.	Weather forecasting, SAF_5		Multiple Members of BVES team are able to proficiently use tool.	31-Dec-23	

Note: An asterisk indicates that the electrical corporation exceeds a particular code, regulation, standard, or best practice. The electrical corporation must provide a reference to the appendix section and page providing further documentation, justification, and substantiation.

Table 8-28 Situational Awareness Initiative Objectives (10-year plan)

Objectives for Ten Years (2026-2032)	Applicable Initiative(s), Tracking ID(s)	Applicable Regulations, Codes, Standards, and Best Practices (See Notes)	Method of Verification (i.e., program)	Completion Date	Reference (Section and Page Number)
Evaluate effectiveness of installing cameras, infrared detectors, LiDAR instruments, and other technologies on overhead assets to provide remote monitoring.	Grid monitoring systems SAF_2, Ignition detection systems SAF_4		Meeting minutes discussing the installation, cost-benefit discussion and review of tracking metrics	31-Dec-2033	

Note: An asterisk indicates that the electrical corporation exceeds a particular code, regulation, standard, or best practice. The electrical corporation must provide a reference to the appendix section and page providing further documentation, justification, and substantiation.

8.3.1.2 Targets

Initiative targets are forward-looking quantifiable measurements of activities identified by each electrical corporation in its WMP. Electrical corporations will show progress toward completing targets in subsequent reports, including QDRs and WMP Updates.

The electrical corporation must list all targets it will use to track progress on its situational awareness and forecasting for the three years of the Base WMP. Energy Safety's Compliance Assurance Division and third parties must be able to track and audit each target.31 For each initiative target, the electrical corporation must provide the following:

- *Utility Initiative Tracking IDs.*
- *Projected targets for each of the three years of the Base WMP and relevant units.*
- *The expected "x% risk impact" For each of the three years of the Base WMP. The expected x% risk impact is the expected percentage risk reduction per year, as described in Section 7.2.2.2.*
- *Method of verifying target completion.*

The electrical corporation's targets must provide enough detail to effectively inform efforts to improve the performance (i.e., reduction in ignition probability or wildfire consequence) of the electrical corporation's situational awareness and forecasting initiatives.

Table 8-29 Situational Awareness Initiative Targets by Year

Initiative Activity	Tracking ID	Units	2023 Target	X% Risk Impact 2023	2024 Target	X% Risk Impact 2024	2025 Target	X% Risk Impact 2025	Method of Verification
Environmental monitoring systems	SAF_1	Ongoing Monitoring and Maintenance	100 %		100 %		100 %		Budget Review
Grid monitoring systems	SAF_2	Number of FIS installed.	30		0		0		Quantitative
Grid monitoring systems	SAF_3	Number of circuits installed on per year.	2		1		1		Quantitative
Ignition detection systems	SAF_4	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Weather forecasting	SAF_5	Ongoing Monitoring and Maintenance	100 %		100 %		100 %		Budget Review
Fire potential index	SAF_6	Ongoing Monitoring and Maintenance	100 %		100 %		100 %		Budget Review

8.3.1.3 Performance Metrics

Performance metrics indicate the extent to which an electrical corporation's Wildfire Mitigation Plan is driving performance outcomes. Each electrical corporation must:

- *List the performance metrics the electrical corporation uses to evaluate the effectiveness of its situational awareness and forecasting in reducing wildfire and PSPS risk*

For each of these performance metrics listed, the electrical corporation must:

- *Report the electrical corporation's performance since 2020 (if previously collected)*
- *Projected performance for 2023-2025*
- *List method of verification*

The electrical corporation must ensure that each metric's name and values are the same in its WMP reporting as its QDR reporting (specifically, QDR Table 2 and QDR Table 3). Metrics listed in this section that are the same as performance metrics required by Energy Safety and reported in QDR Table 2 (Performance Metrics) must match those reported in QDR Table 2. Metrics listed in this section that are not the same as any of the performance metrics identified by Energy Safety and reported in QDR Table 2 must match those reported in QDR Table 3.

The electrical corporation must:

- *Summarize its self-identified performance metric(s) in tabular form*
- *Provide a brief narrative that explains trends in the metrics*

Table 8-24 provides an example of the minimum acceptable level of information.

Table 8-30 Situational Awareness and Forecasting Performance Metrics Results by Year

Performance Metrics	Unit	2020	2021	2022	2023 Projected	2024 Projected	2025 Projected	Method of Verification (e.g., third-party evaluation, QDR)

8.3.2 Environmental Monitoring Systems

The electrical corporation must describe its systems, processes, and procedures used to monitor environmental conditions within its service territory. These observations should inform the electrical corporation's near-real-time risk assessment and weather forecast validation. The electrical corporation must document the following:

- *Existing systems, technologies, and processes*
- *How the need for additional systems is evaluated*
- *Implementation schedule for any planned additional systems*
- *How the efficacy of systems for reducing risk are monitored*

Reference the Utility Initiative Tracking ID where appropriate.

8.3.2.1 Existing Systems, Technologies, and Processes

The electrical corporation must report on the environmental monitoring systems and related technologies and procedures currently in use, highlighting any improvements made since the last WMP submission. At a minimum, the electrical corporation must discuss systems, technologies, and procedures related to the reporting of the following:

- *Current weather conditions:*
- *Air temperature*
- *Relative humidity*
- *Wind velocity (speed and direction)*
- *Fuel characteristics:*
- *Seasonal trends in fuel moisture*

Each system must be summarized in Table 8-25. The electrical corporation must provide the following additional information for each system in the accompanying narrative:

- *Generalized location of the system / locations measured by the system (e.g., HTFD, entire service territory).*
- *Integration with the broader electrical corporation's system.*
- *How measurements from the system are verified.*
- *Frequency of maintenance. • For intermittent systems (e.g., aerial imagery, line patrols), what triggers collection. This should include flow charts and equations as appropriate.*
- *For calculated quantities, how raw measurements are converted into calculated quantities. This should include flow charts and equations as appropriate.*

Table 8-31 Environmental Monitoring Systems

System	Location	Measurement/Observation	Frequency	Purpose and Integration	Maintenance Schedule
Weather Stations	20 across entire BVES service territory (See Table Below)	Air Temperature Wind Velocity & Direction (Steady & Gust) Relative Humidity Barometric Pressure Precipitation	Continuous Monitoring	Improved weather monitoring and forecasting Model Validation SCADA Connected	
HD Cameras (ALERTWildfire HD Cameras)	15 cameras in 7 Key Locations Across BVES	Visual Observation	Continuous During Hazardous Conditions	Visual Awareness in areas adjacent to electrical	

	service Territory			assets. Immediate fire alert	

Table 8-32 Weather Station List

Weather Station Name	Pole Number	Year of Installation	Latitude	Longitude
Big Bear Dam	1210284CTC	2020	34.24227667	-116.97761740
North Shore	6984BV	2019	34.24532883	-116.97341180
Fawnskin	12535BV	2020	34.26380082	-116.93446430
Division		2020	34.26186422	-116.86659300
Paradise	11000BV	2020	34.26652527	-116.84013820
Baldwin	10170BV	2020	34.29375365	-116.81310840
Pioneer	11967BV	2019	34.26318578	-116.79065270
Erwin Lake	7025BV	2020	34.2429703	-116.8006365
Erwin	12671BV	2019	34.23298191	-116.79211290
Lake Williams	9607BV	2020	34.23198312	-116.77332380
Sunrise	9784BV	2019	34.25554307	-116.82382920
Sugarloaf	5026BV	2020	34.24301379	-116.83739720
Clubview	13117BV	2019	34.24027965	-116.86800240
Goldmine	6940BV	2019	34.232107	-116.845663
Garstin	13050BV	2019	34.24588032	-116.88580580
Boulder	12524BV	2019	34.2386084	-116.9376263
Lagunita	11054BV	2019	34.24732716	-116.93515330
2N10	4254BV	2021	34.209833	-116.904333
Radford	12188BV	2019	34.20184	-116.90551
Lake View		2021	34.267380,	-116.880145

Table 8-33 ALERT Wildfire HD Camera List

ALERT Wildfire HD Camera (Quantity)	Latitude	Longitude
Bear Mountain (5)	34.21260737482088	-116.86633705780157
Snow Summit (2)	34.22276789245118	-116.89473063338028
Lake Williams is now “Deadman’s Ridge” (2)	34.232954204525576	-116.79212344081046
Bertha Peak is now “Lakeview” (2)	34.267381554648416	-116.88014786493233
KBHR (2)	34.27789572286411	-116.79304190092348
*Onyx Peak (2)	34.19126270322101	-116.70940870018705
*Keller Peak (2)	34.19680815454194	-117.04922917574402

8.3.2.2 Evaluation and Selection of New Systems

The electrical corporation must describe how it evaluates the need for additional environmental monitoring systems. This description must include:

- *How the electrical corporation evaluates the impact of new systems on reducing risk (e.g., expected quantitative improvement in weather forecasting)*
- *The electrical corporation's process to evaluate the efficacy of new technologies*

These descriptions should include flow charts as appropriate to describe the process.

BVES evaluates risk of its assets two times per year. Updated evaluations include any installations of new systems and the reduction of overall risk to the system.

BVES also evaluates new systems by actual performance (reductions in outages, reductions in line contacts, etc.). If new systems are not performing as expected, then additional situational awareness and forecasting systems are considered. In addition, if a new technology is found that will improve safety, then it will be evaluated and considered.

8.3.2.3 Planned Improvements

The electrical corporation must describe its planned improvements for its environmental monitoring systems. This must include any plans for the following:

- *Expansion of existing systems*
- *Establishment of new systems*

For each planned improvement, the electrical corporation must provide the following in Table 8-26:

- *Description – A description of the planned initiative activity*
- *Impact – Reference to and description of the impact of the initiative activity on each risk and risk component*
- *Prioritization – A description of the x% risk impact (see Section 8.1.1.2 for explanation)*
- *Schedule – A description of the planned schedule for implementation*

Table 8-34 Planned Improvements to Environmental Monitoring Systems

System	Description	Impact	X% Risk Impact	Implementation Schedule
N/A	N/A	N/A	N/A	N/A

At the present time, BVES does not have plans to implement additional environmental monitoring systems. BVES believes its HD cameras as well as weather stations coupled with its investment in Technosylva, and the contract meteorologist provide adequate environmental monitoring. BVES will continue to work in partnership with Technosylva, UCSD, CAL FIRE, and Big Bear Fire department to determine if additional cameras or weather stations would be beneficial in providing granularity to the conditions within BVES's service territory.

8.3.2.4 Evaluating Mitigation Initiatives

The electrical corporation must describe the processes and procedures for the ongoing evaluation of the efficacy of its environmental monitoring program.

BVES will continue to work in partnership with Technosylva, UCSD, CAL FIRE, and Big Bear Fire department to determine if additions to existing system, or additional systems are needed.

- Technosylva will be provide clarity if sufficient data is being provided for monitoring and forecasting.
- UCSD, CAL FIRE & Big Bear Fire Department will provide insight into service area visibility and if the current array of camera's sufficiently covers the BVES service territory and allows for accurate monitoring of current conditions in the service territory and the surrounding area.

8.3.3 Grid Monitoring Systems

The electrical corporation must describe its systems, processes, and procedures used to monitor the operational conditions of its equipment. These observations should inform the electrical corporation's near-real-time risk assessment. The electrical corporation must document:

- *Existing systems, technologies, and processes*
- *Process used to evaluate the need for additional systems*
- *Implementation schedule for any planned additional systems*
- *How the efficacy of systems for reducing risks are monitored*

Reference the Utility Initiative Tracking ID where appropriate.

8.3.3.1 Existing Systems, Technologies, and Processes

The electrical corporation must report on the grid system monitoring systems and related technologies and processes currently in use, highlighting any improvements made since the last WMP submission. At a minimum, the electrical corporation must discuss systems/technologies related to the detection of:

- *Faults (e.g., fault anticipators, Rapid Earth Fault Current Limiters, etc.)*
- *Failures*
- *Recloser operations*

Each system must be summarized in Table 8-27 below. The electrical corporation must provide the following information for each system in the accompanying narrative:

- *Location of the system / locations measured by the system*
- *Integration with the broader utility system*
- *How measurements from the system are verified*
- *For intermittent systems (e.g., aerial imagery, line patrols), the processes used to trigger collection. This should include flow charts and equations as appropriate to describe the process*

- *For calculated quantities,*
- *how raw measurements are converted to calculated quantities. This should include flow charts and equations as appropriate.*

Table 8-35 Grid Operation Monitoring Systems

System	Measurement/Observation	Frequency	Purpose and Integration
EGM Meta-Alert System	Fault Monitoring due fire, grounding, or third-party impact	Real-Time	Real-time monitoring of Pioneer Circuit
Fault Indicators	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. As of 2022 209 have been installed on the system

8.3.3.2 Evaluation and Selection of New Systems

The electrical corporation must describe how it evaluates the need for additional grid operation monitoring systems. This description must include:

- *How the electrical corporation evaluates the impact of new systems on reducing risk (e.g., expected reduction in ignitions from failures, expected reduction in failures)*
- *How BVES evaluates the efficacy of new technologies*

These descriptions should include flow charts as appropriate to describe the process.

See Section 8.3.2.2

8.3.3.3 Planned Improvements

The electrical corporation must describe its planned improvements in its grid operation monitoring systems. This must include any plans for the following:

- *Expansion of existing systems*
- *Establishment of new systems*

For each planned improvement, the electrical corporation must provide the following in Table 8-26:

- *Description – A description of the planned initiative activity*
- *Impact – Reference to and description of the impact of the initiative activity on each risk and risk component*

- *Prioritization – A description of the x% risk impact (see Section 8.1.1.2 for explanation)*
- *Schedule – A description of the planned schedule for implementation*

Table 8-36 Improvements to Grid Operation Monitoring Systems

System	Description	Impact	X% Risk Impact	Implementation Schedule
Fault Indicators	Install additional Fault Indicators	Reduce Risk of Spark or Ignition Reduce fault idinetification and location time to improve service resotoration		129 in 2023

8.3.3.4 Evaluating Mitigation Initiatives

BVES must describe its procedures for the ongoing evaluation of the efficacy of its grid operation monitoring program.

BVES will continue to do twice annual evaluation of its assets. In the case of Grid Monitoring Systems (Fault Indicators & EGM Meta-Alert) BVES will monitor the annual CAIDI for circuits that have the monitoring assets versus prior to asset implementation. BVES will also conduct cost-benefit analysis as it related to risk reduction (the primary goal of the WMP) to determine if the program is meeting the threshold originally planned prior to implementation.

8.3.3.5 Enterprise System for Grid Monitoring

In this section, the electrical corporation must provide an overview of its enterprise system for grid monitoring. This overview must include discussion of:

- *Any database(s) utilized for storage*
- *Describe the utilities internal documentation of its database(s)*
- *Integration with systems in other lines of business*
- *Describe any QA/QC or auditing of its system*
- *Describe internal processes for updating enterprise system including database(s)*
- *Any changes to the initiative since the last WMP submission and a brief explanation as the why those changes were made. Include any planned improvements or updates to the initiative and timeline for implementation*

BVES - Describe current grid monitoring system – SCADA et al

8.3.4 Ignition Detection Systems

The electrical corporation must describe its systems, technologies, and procedures used to detect ignitions within its service territory and gauge their size and growth rates.

The electrical corporation must document the following:

- *Existing ignition detection sensors and systems*
- *Evaluation and selection of new ignition detection systems*
- *Planned integration of new ignition detection technologies*
- *Monitoring of mitigation improvements*

Reference the Utility Initiative Tracking ID where appropriate.

8.3.4.1 Existing Ignition Detection Sensors and Systems

The electrical corporation must report on the ignition detection sensors and systems, along with related technologies and processes, that are currently in use, highlighting any improvements made since the last WMP submission. At a minimum, the electrical corporation must document the deployment of each of the following:

- *Early fire detection:*
- *Satellite infrared imagery*
- *High-definition video*
- *Infrared cameras*
- *Fire growth potential software*

The electrical corporation must summarize each system in Table 8-29 below. It must provide the following additional information for each system in an accompanying narrative:

- *General location of detection sensors (e.g., HFTD or entire service territory)*
- *Resiliency of sensor communication pathways*
- *Integration of sensor data into machine learning or AI software*
- *Role of sensor data in risk response*
- *False positives filtering*
- *Time between detection and confirmation*
- *Security measures for network-based sensors*

Table 8-37 Exemplar Fire Detection Systems Currently Deployed

Detection System	Capabilities	Companion Technologies	Contribution to Fire Detection and Confirmation
HD Cameras (ALERTWildfire HD Cameras)	Continuous Monitoring During	Technosylva – Fire Growth Potential Software	Visual Awareness in areas adjacent to electrical assets.

	Hazardous Conditions 15 cameras in 7 Key Locations Across BVES service Territory		Immediate fire alert

Table 8-38 ALERT Wildfire HD Camera List

ALERT Wildfire HD Camera (Quantity)	Latitude	Longitude
Bear Mountain (5)	34.21260737482088	-116.86633705780157
Snow Summit (2)	34.22276789245118	-116.89473063338028
Lake Williams is now "Deadman's Ridge" (2)	34.232954204525576	-116.79212344081046
Bertha Peak is now "Lakeview" (2)	34.267381554648416	-116.88014786493233
KBHR (2)	34.27789572286411	-116.79304190092348
*Onyx Peak (2)	34.19126270322101	-116.70940870018705
*Keller Peak (2)	34.19680815454194	-117.04922917574402

8.3.4.2 Evaluation and Selection of New Detection Systems

The electrical corporation must describe how it evaluates the need for additional ignition detection technologies. This description must include:

- *How the electrical corporation evaluates the impact on new detection technologies on reducing and improving detection and response times*
- *The electrical corporation's process to evaluate the efficacy of new technologies*
- *The electrical corporation's budgeting process for new detection system purchases*

See Section 8.3.2.2

8.3.4.3 Planned Integration of New Detection Technologies

The electrical corporation must provide an implementation schedule for new ignition detection and alarm system technologies. This must include any plans for the following:

- *Integration of new systems into existing physical infrastructure*
- *Integration of new systems into existing data analysis*
- *Increases in budgets and staffing to support new systems*

For each new technology system, the electrical corporation must provide the following in Table 8-28:

- *Description – A description of the technology's capabilities*
- *Impact – A description of the impact the technology will have on each risk and risk component*
- *Prioritization – A description of the x% risk impact (see Section 8.1.1.2 for explanation)*
- *Schedule – A description of the planned schedule for implementation*

Table 8-39 Planning Improvements to Fire Detection and Alarm Systems

System	Description	Impact	X% Risk Impact	Implementation Schedule
N/A	N/A	N/A	N/A	N/A

At present, BVES does not plan to implement additional Ignition Detection systems. BVES believes its HD cameras coupled with its investment in Technosylva provide adequate ignition detection and forecasting of fire spread. BVES will continue to work in partnership with Technosylva, UCSD, CAL FIRE, and Big Bear Fire Department to determine if additional cameras would be beneficial in providing granularity to the conditions within BVES's service territory.

8.3.4.4 Evaluating Mitigation Initiatives

The electrical corporation must describe its procedures for the ongoing evaluation of the efficacy of its fire detection systems.

BVES will continue to work in partnership with Technosylva, UCSD, CAL FIRE, and Big Bear Fire department to determine if additions to existing system, or additional systems are needed.

- Technosylva will be provide clarity if sufficient data is being provided for monitoring and forecasting.
- UCSD, CAL FIRE & Big Bear Fire Department will provide insight into service area visibility and if the current array of camera's sufficiently covers the BVES service territory and allows for accurate monitoring of current conditions in the service territory and the surrounding area.

8.3.4.5 Enterprise System for Ignition Detection

In this section, the electrical corporation must provide an overview of its enterprise system for ignition detection. This overview must include discussion of:

- *Any database(s) utilized for storage*
- *Describe the electrical corporation's internal documentation of its database(s)*
- *Integration with systems in other lines of business*
- *Describe any QA/QC or auditing of its system*
- *Describe internal processes for updating enterprise system including database(s)*

- *Any changes to the initiative since the last WMP submission and a brief explanation as the why those changes were made. Include any planned improvements or updates to the initiative and timeline for implementation*

8.3.5 Weather Forecasting

The electrical corporation must describe its systems, processes, and procedures used to forecast weather within its service territory. These forecasts should inform the electrical corporation's near-real-time-risk assessment and PSPS decision-making processes. The electrical corporation must document the following:

- *Existing modeling approach*
- *Known limitations of existing approach*
- *Implementation schedule for any planned changes to the system*
- *Process to monitor the efficacy of systems at reducing risk*

Reference the Utility Initiative Tracking ID where appropriate.

8.3.5.1 Existing Modeling Approach

At a minimum, the electrical corporation must discuss the following components of weather forecasting:

- *Data assimilation from environmental monitoring systems within the electrical corporation service territory*
- *Ensemble forecasting with control forecast and perturbations*
- *Model inputs including, for example:*
- *Land cover / land use type*
- *Local topography*
- *Model outputs including, for example:*
- *Air temperature*
- *Barometric pressure*
- *Relative humidity*
- *Wind velocity (speed and direction)*
- *Solar radiation*
- *Rainfall duration and amount*
- *Separate modules (e.g., local weather analysis and local vegetation analysis)*
- *Subject matter expert (SME) assessment of forecasts*
- *Spatial granularity of forecasts including:*
- *Horizontal resolution*

- *Vertical resolution*
- *Time horizon of the weather forecast throughout the service territory*

The electrical corporation must highlight improvements made to the electrical corporation's weather forecasting since the last WMP submission

The electrical corporation must also provide documentation of its modeling approach pertaining to its weather forecasting system in accordance with the requirements in Appendix B.

BVES contracts with a meteorologist to provide at least weekly focused weather forecasts tailored to BVES's service area, and forecasts evaluating the prevailing fire threat. 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.

BVES's use of Technosylva while focused on risk and fire spread modeling does incorporate weather inputs which have been gathered from both the weather consultant as well as the weather stations BVES has within its service territory. The Technosylva model considers both current and future state conditions for the BVES service territory.

8.3.5.2 Known Limitations of Existing Approach

BVES must describe any known limitations of its existing modeling approach resulting from assumptions, data availability, and computational resources. It must discuss the impact of these limitations on the modeling outputs.

Technosylva's modeling outputs are greatly dependent on the quality of data provided by BVES and its weather assets. Due to the topography and microclimates of BVES's service territory it is possible that the weather data provided could me more granular. This granularity could yield a more accurate model output.

8.3.5.3 Planned Improvements

The electrical corporation must describe its planned improvements in its weather forecasting systems. This must include any plans for the following:

- *Increase in model validation*
- *Increase in spatial granularity*
- *Decrease in limitations by removal of assumptions*
- *Increase in input data quality*
- *Increase in related frequency*

For each planned improvement, the electrical corporation must provide the following in Table 8-31:

- *Description – A description of the planned initiative activity*
- *Impact – Reference to and description of the impact of the initiative activity on each risk and risk component*
- *Prioritization – A description of the x% risk impact (see Section 8.1.1.2 for explanation)*

- *Schedule – A description of the planned schedule for implementation*

Table 8-31. Exemplar Planned Improvements to Weather Forecasting Systems

System	Description	Impact	X% Risk Impact	Implementation Schedule
N/A	N/A	N/A	N/A	N/A

BVES does not have and planned changes or improvements in its engagement with its weather consultant.

All ongoing efforts with Technosylva and its modeling capabilities can be found in Section 6.

8.3.5.4 Evaluating Mitigation Initiatives

BVES *must describe its procedures for the ongoing evaluation of the efficacy of its weather forecasting program*.

BVES evaluates risk of its assets two times per year. Updated evaluations include any installations of new systems or programs and the reduction of overall risk to the system. BVES also evaluates programs by actual performance (reductions in outages, reductions in line contacts, etc.) and makes determinations on its efficacy.

8.3.5.5 Enterprise System for Weather Forecasting

In this section, the electrical corporation must provide an overview of its enterprise system for weather forecasting. This overview must include discussion of:

- *Any database(s) used for storage*
- *Describe the utilities internal documentation of its database(s)*
- *Integration with systems in other lines of business*
- *Describe any QA/QC or auditing of its system*
- *Describe internal processes for updating enterprise system including database(s)*
- *Any changes to the initiative since the last WMP submission and a brief explanation as the why those changes were made. Include any planned improvements or updates to the initiative and timeline for implementation*

BVES does not have an enterprise system for weather forecasting at this time nor does it have plans to acquire such a system.

8.3.6 Fire Potential Index

The electrical corporation must describe its process for calculating its fire potential index (FPI) or a similar a landscape scale index used as a proxy for assessing real-time risk of a wildfire under current and forecasted weather conditions. The electrical corporation must document the following:

- *Existing calculation approach and how its FPI is used in its operations*

- *The known limitations of its existing approach*
- *Implementation schedule for any planned changes to the system.*

Reference the Utility Initiative Tracking ID where appropriate.

Please reference Section 6 for BVES's use of Technosylva and its risk, and fire potential modeling.

8.3.6.1 Existing Calculation Approach and Use

The electrical corporation must describe:

- *How it calculates its own FPI or if uses an external source, such as the United States Geological Survey*
- *How it uses its or an FPI in its operations*

Additionally, if the electrical corporation calculates its own FPI, it must provide tabular information regarding the features of its FPI. Table 8-32 provides a template for the required information.

Table 8-40 FPI Features

Feature Group	Feature	Altitude	Description	Source	Update Cadence	Spatial Granularity	Temporal Granularity
See Statement Below							

Please reference Section 6 for BVES's use of Technosylva and its risk, and fire potential modeling.

8.3.6.2 Known Limitations of Existing Approach

The electrical corporation must describe any known limitations of current FPI calculation.

Please reference Section 6 for BVES's use of Technosylva and its risk, and fire potential modeling.

8.3.6.3 Planned Improvements

The electrical corporation must describe its planned improvements for its FPI including a description of the improvement and the planned schedule for implementation

Table 8-41 Exemplar Planned Improvements to Ignition Likelihood Calculation

System	Description	Impact	X% Risk Impact	Implementation Schedule

Please reference Section 6 for BVES's use of Technosylva and its risk, and fire potential modeling.

8.4 Emergency Preparedness

8.4.1 Overview

Each electrical corporation must develop and adopt an emergency preparedness plan in compliance with the standards established by the CPUC pursuant to Public Utilities Code section 768.6(a). Wildfires and PSPS introduce unique risk management challenges requiring the electrical corporation to evaluate, develop, and implement wildfire- and PSPS-specific emergency preparedness activities as part of a holistic emergency preparedness strategy.

In this section, the electrical corporation must identify objectives for the next 3- and 10-year periods, targets, and performance metrics related to the following emergency preparedness programmatic areas:

- *Wildfire and PSPS emergency preparedness plan*
- *Collaboration and coordination with public safety partners*
- *Public notification and communication strategy*
- *Preparedness and planning for service restoration*
- *Customer support in wildfire and PSPS emergencies*
- *Learning after wildfire and PSPS events*

BVES has an Emergency and Disaster Recovery Plan (EDRP) that sets forth how BVES will respond to emergencies and disasters, including PSPS activations, by either BVES or a cut of the supply lines by a PSPS initiated by Southern California Edison (SCE). Both the EDRP and the PSPS Protocols comply with CPUC protocols including, but not limited to, Public Utilities Code section 768.6(a).

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, or extreme heat may adversely impact the integrity of the distribution system, resulting in occasional interruptions of electrical service. The distribution system is also susceptible to damage because of major disasters, such as earthquakes, flooding, wildfires, and mud and rockslides. 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 potions 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 also be susceptible to outages caused by events outside of its services area. All 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 or 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. Accordingly, the EDRP is 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 is easily adapted to major outages caused by other causes. It is also recognized that no plan can perfectly predict or respond to every emergency. Therefore, the EDRP provides a structure based on a set of 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 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. 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 Bear Valley Electric Service, Inc. Emergency & Disaster
- 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 working relationships be established before emergency response is necessary. Understanding stakeholders' key staff, contact information, roles and responsibilities, and capabilities are extremely useful in achieving successful emergency response.

8.4.1.1 Objectives

Each electrical corporation must summarize the objectives for its 3-year and 10-year plans for implementing and improving its emergency preparedness.33 These summaries must include the following:

- *Identification of which initiative(s) in the WMP the electrical corporation is implementing to achieve the stated objective, including Utility Initiative Tracking IDs*
- *Reference(s) to applicable codes, standards, and best practices/guidelines and an indication of whether the electrical corporation exceeds an applicable code, standard, or regulation*
- *Method of verifying achievement of each objective*
- *A completion date for when the electrical corporation will achieve the objective*
- *Reference(s) to the WMP section(s) or appendix, including page numbers, where the details of the objective(s) are documented and substantiated*

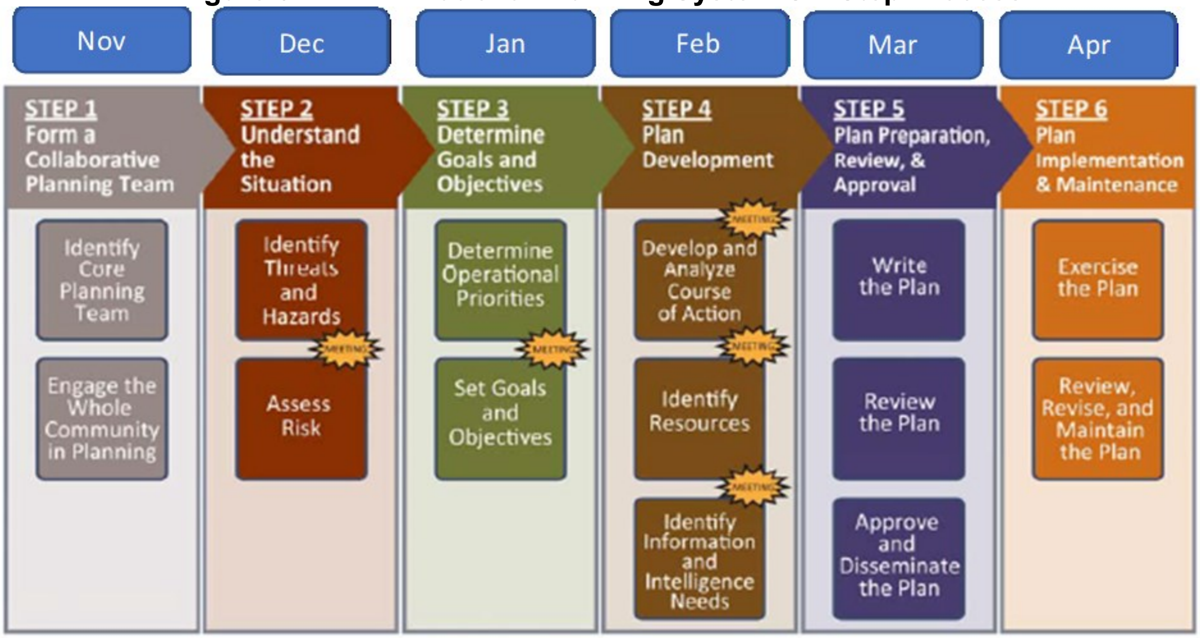
This information must be provided in Table 8-32 for the 3-year plan and Table 8-33 for the 10-year plan. Exemplars of the minimum acceptable level of information are provided below.

BVES leverages the protocols included in the company's ERDP to learn from wildfire events in the same manner the utility learns from any emergency event. The criticality and scope of the BVES EDRP has grown over the past few years. To meet these challenges, emergency preparedness and response activities must be systematic, inclusive, and transparent to review incidents in a manner that is aligned with our core values.

BVES does not have any specific future improvements for emergency preparedness identified at this time. The ERDP is reviewed annually and updated as necessary due to changes in requirements, lessons learned, changes to the grid, and suggestions from stakeholders in the community. For example, once the Radford Line covered conductor project is complete, BVES will update its ERDP to reflect the new capabilities of the Radford Line (e.g., not de-energizing it from April to October).

Starting In 2023, BVES is utilizing the FEMA National Planning System Six Step process to update the EDRP. The EDRP review will begin in November and end in April with a step performed each month: Step 1 Form a Collaborative Planning Team, Step 2, Understand the Situation, Step 3, Determine Goals and Objectives, Step 4, Plan Development, Step 5 Plan Preparation, Review and Approval, Step 6, Plan implementation & Maintenance. BVES will review the EDPR every year and update it as necessary. Figure 8-4 outlines the FEMA Six Step process.

Figure 8-4 FEMA National Planning System Six Step Process



For the PSPS plan, no direct lessons learned from BVES-initiated activations can be applied to this WMP Update because BVES has not met its thresholds to initiate a PSPS event between 2020 through 2022. However, Bear Valley has followed other utilities' experience and has added lessons learned from elsewhere into its PSPS Plan. The triggering threshold has also not changed based on the implementation of WMP initiatives. In the future, BVES anticipates continued re-designation of high-risk areas to reduced risk designations after years of significant WMP initiative implementation. BVES will re-evaluate its PSPS trigger thresholds to determine if they remain appropriate as mitigations are deployed and real-time modeling capabilities are enhanced.

In 2022, BVES contracted with Technosylva in an effort to provide real-time situational awareness through on-demand fire spread predictions and impact analysis, wildfire risk forecasting for customer assets and the service area using daily weather prediction integration and asset risk analysis using historical weather climatology. Additional quantitative analysis of this projected evolution will be available over the year with full deployment in 2023. This additional awareness may also lead to changes of BVES's PSPS activation thresholds or PSPS Protocol.

In mid-2022, BVES is updating its current PSPS Plan and Protocols to align with Phase 3 de-energization guidelines issued under D. 21-06-034.

BVES has not initiated any PSPS events over the past three years and does not forecast an imminent need to de-energize in the future based on a one, three, or ten-year forecast.

Table 8-42 Emergency Preparedness Initiative Objectives (3-year plan)

Objectives for Three Years (2023-2025)	Applicable Initiative(s),	Applicable Regulations, Codes, Standards,	Method of Verification (i.e., program)	Completion Date	Reference (Section

	Tracking ID(s)	and Best Practices (See Notes)			and Page Number)
Improve staff training on emergency and disaster response plan through a combination of classroom instruction, tabletop exercises, and functional drills.	Emergency preparedness plan, EP_1			31-Dec-25	
Increase coordination with community stakeholders in emergency response.	External collaboration and coordination, EP_2			31-Dec-25	
Develop robust lines and layers of communication s with stakeholders and customers.	Public emergency communicatio n strategy, EP_3			31-Dec-25	
Integrate plan to restore service after an outage due to a wildfire or PSPS event.	Preparedness and planning for service restoration, EP_4			31-Dec-25	
Establish strong programs, systems, and protocols to support residential and non- residential customers in wildfire emergencies and PSPS events.	Customer support in wildfire and PSPS emergencies, EP_5			31-Dec-25	

Note: An asterisk indicates that the electrical corporation exceeds a particular code, regulation, standard, or best practice. The electrical corporation must provide a reference to the appendix section and page providing further documentation, justification, and substantiation.

Table 8-43 Emergency Preparedness Initiative Objectives (10-year plan)

Objectives for Ten Years (2026-2032)	Applicable Initiative(s), Tracking ID(s)	Applicable Regulations, Codes, Standards, and Best Practices (See Notes)	Method of Verification (i.e., program)	Completion Date	Reference (Section and Page Number)
Integrate emergency response plan with stakeholder emergency response plans	Emergency preparedness plan, EP_1 External collaboration and coordination, EP_2				
Evaluate increase use of social media and technology to improve and streamline communications with stakeholders and customers.	Public emergency communication strategy, EP_3				

Note: An asterisk indicates that the electrical corporation exceeds a particular code, regulation, standard, or best practice. The electrical corporation must provide a reference to the appendix section and page providing further documentation, justification, and substantiation.

8.4.1.2 Targets

Initiative targets are quantifiable measurements of activities identified in the WMP. Electrical corporations will show progress towards completing targets in subsequent reports, including QDRs and WMP Updates.

The electrical corporation must list all targets it will use to track progress on its emergency preparedness for the next three years (2023–2025). Energy Safety's Compliance Assurance Division and third parties must be able to track and audit each target.34 For each initiative target, the electrical corporation must provide the following:

- *Utility Initiative Tracking IDs*
- *Projected targets for the three years of the Base WMP and relevant units*
- *For 2023–2025, the "x% risk impact." The x% risk impact is the percentage risk reduction identified in Table 7-2 for a specific mitigation initiative (see Section 7.2.2.1 for calculation instructions)*
- *Method of verifying target completion*

The electrical corporation's targets must provide enough detail to effectively inform efforts to improve the performance (i.e., reduction in wildfire consequence) of the electrical corporation's emergency preparedness initiatives.

An exemplar of the minimum acceptable level of information is provided in Table 8-34.

Table 8-44 Emergency Preparedness Initiative Targets by Year

Initiative Activity	Tracking ID	Units	2023 Target	X% Risk Impact 2023	2024 Target	X% Risk Impact 2024	2025 Target	X% Risk Impact 2025	Method of Verification
Emergency preparedness plan	EP_1	Review and Evaluate PSPS Program	Finalize Review of PSPS Program		Finalize Review of PSPS Program		Finalize Review of PSPS Program		Version History
External collaboration and coordination	EP_2	Review and Evaluate PSPS Program	Finalize Review of PSPS Program		Finalize Review of PSPS Program		Finalize Review of PSPS Program		Version History
Public emergency communication strategy	EP_3	Review and Evaluate PSPS Program	Finalize Review of PSPS Program		Finalize Review of PSPS Program		Finalize Review of PSPS Program		Version History
Preparedness and planning for service restoration	EP_4	Review and Evaluate PSPS Program	Finalize Review of PSPS Program		Finalize Review of PSPS Program		Finalize Review of PSPS Program		Version History
Customer support in wildfire and PSPS emergencies	EP_5	Review and Evaluate PSPS Program and Customer	Finalize Review of PSPS Program and Verify Customer		Finalize Review of PSPS Program and Verify Customer		Finalize Review of PSPS Program and Verify Customer		Version History

		Needs Met	Needs Met		Needs Met		Needs Met		

8.4.1.3 Performance Metrics

Performance metrics indicate the extent to which an electrical corporation's Wildfire Mitigation Plan is driving performance outcomes. Each electrical corporation must:

- *List the performance metrics the electrical corporation uses to evaluate the effectiveness of its emergency preparedness in reducing wildfire and PSPS risk*

For each of these performance metrics listed, the electrical corporation must:

- *Report the electrical corporation's performance since 2020 (if previously collected)*
- *Project performance for 2023-2025*
- *List method of verification*

The electrical corporation must ensure that each metric's name and values are the same in its WMP reporting as its QDR reporting (specifically, QDR Table 2 and QDR Table 3). Metrics listed in this section that are the same as performance metrics required by Energy Safety and reported in QDR Table 2 (Performance Metrics)40 must match those reported in QDR Table 2. Metrics listed in this section that are not the same as any of the performance metrics identified by Energy Safety and reported in QDR Table 2 must match those reported in QDR Table 3.

The electrical corporation must:

- *Summarize its self-identified performance metric(s) in tabular form*
- *Provide a brief narrative that explains trends in the metrics*

An exemplar of the minimum acceptable level of information is provided in Table 8-36.

BVES tracks on an annual basis the Customer Average Interruption Duration Index (CAIDI) for its service territory. CAIDI is a representative performance metric for its Emergency Preparedness as the metric tracks the time to restore power to its customers and allows BVES to view on an average interruption basis if it is improving in its effort. Since 2020 BVES has seen a decline in its CAIDI year over year. BVES believe it will continue to see a decline with a target of 45 minutes for its 2025 CAIDI.

Table 8-45 Emergency Preparedness Performance Metrics Results by Year

Performance Metrics	Units	2020	2021	2022	2023 Projected	2024 Projected	2025 Projected	Method of Verification (e.g., third-party evaluation, QDR)
CAIDI	Minutes	94.5	61.5	31.1	55	50	45	Year End Review

8.4.2 Emergency Preparedness Plan

In this section, the electrical corporation must provide an overview of how it has evaluated, developed, and integrated wildfire- and PSPS-specific emergency preparedness strategies, practices, policies, and procedures into its overall emergency plan based on the minimum standards described in GO 166. The electrical corporation must provide the title of its latest emergency preparedness report, the date of the report, and an indication of whether the plan complies with CPUC R.15-06-009, D.21-05-019, and GO 166. The overview must be no more than two paragraphs.

In addition, the electrical corporation must provide a list of any other relevant electrical corporation documents that govern its wildfire and PSPS emergency preparedness planning for response and recovery efforts. This must be a bullet point list with document title, version (if applicable), and date. For example:

- *Electrical Corporation's Emergency Response Plan (ECERP), dated MM/DD/YYYY*

Reference the Utility Initiative Tracking ID where appropriate.

Section 4 to the BVES Emergency Response and Disaster Plan (EDRP), dated March 31, 2022, explains the BVES system sources of power and actions to be taken when there is partial or complete loss of sources of power, including following the initiation of a PSPS. 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. The PSPS Plan dated January 31, 2023, provides supplemental guidance in the case of an SCE PSPS event leading to a complete or partial loss of all SCE lines to avoid a "black start" of the Bear Valley Power Plant (BVPP). Once PSPS is implemented, outages shall be managed using the guidance of the BVES EDRP and the supplemental guidance of this procedure.

8.4.2.1 Overview of Wildfire and PSPS Emergency Preparedness

In this section of the WMP, the electrical corporation must provide an overview of its wildfire- and PSPS-specific emergency preparedness plan. At a minimum, the overview must describe the following:

- *Purpose and scope of the plan.*
- *Overview of protocols, policies, and procedures for responding to and recovering from a wildfire or PSPS event (e.g., means and methods for assessing conditions, decision-making framework, prioritizations). This must include:*
- *An operational flow diagram illustrating key components of its wildfire- and PSPS-specific emergency response procedures from the moment of activation to response, recovery, and restoration of service.*
- *Separate overviews and operational flow diagrams for wildfires and PSPS events.*
- *Key personnel, qualifications, and training.*
- *Resource planning and allocation (e.g., staffing).*
- *Drills, simulations, and tabletop exercises.*
- *Coordination and collaboration with public safety partners (e.g., emergency planning, interoperable communications).*
- *Notification of and communication to customers during and after a wildfire or PSPS event.*
- *Improvements/updates made since the last WMP submission.*

BVES approaches wildfire and PSPS emergency preparedness is to utilize the EDRP and PSPS plan to effectively and efficiently respond for a loss of power including via a proactive de-energization. BVES's 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 ("PUCs") § 451 and 399.2(a).

To prepare for a Wildfire or PSPS event, BVES will perform the following activities:

- Deploy wildfire response team(s) to high fire risk areas,
- Adjust protective device settings optimized for fire prevention,
- Increase frequency of consultant meteorologist forecast,
- 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 Access and Functional Needs populations that may be impacted,
- Prepare to activate Community Resource Center (CRC),
- Activation of Emergency Operations Center and Emergency Response Plan,
- Prepare Bear Valley Power Plant for sustained operations,
- Conduct switch operations to minimize impact of potential PSPS activity,
- Engage temporary generation, and
- Activate CRC.

In addition, the electrical corporation must provide a table with a list of current gaps and limitations in evaluating, developing, and integrating wildfire- and PSPS-specific preparedness and planning features into its overall emergency preparedness plan(s). Where gaps exist, the electrical corporation must provide a remedial action plan and timeline for resolving. Table 8-36 provides an exemplar of the minimum level of content and detail required for this information.

Table 8-46 Key Gaps and Limitations in Integrating Wildfire- and PSPS-Specific Strategies into Emergency Plan

Gap or Limitation Subject	Remedial Brief Description	Remedial Action Plan

8.4.2.2 Key Personnel, Qualifications, and Training

In this section, the electrical corporation must provide an overview of the key personnel constituting its emergency planning, preparedness, response, and recovery team(s) for wildfire and PSPS events. This includes identifying key roles and responsibilities, personnel resource planning (internal and external staffing needs), personnel qualifications, and required training programs.

Personnel Qualifications

The electrical corporation must report on the various roles, responsibilities, and qualifications of electrical corporation and contract personnel tasked with wildfire emergency preparedness planning, preparedness, response, and recovery, and those tasked for PSPS-related events. This may include representatives from administration, information technology (IT), human resources, communications, electrical operations, facilities, and any other mission-critical units in the electrical corporation. As part of this section, the electrical corporation must provide a brief narrative on how it determined its personnel resource planning for various key roles and responsibilities. The narrative must be no more than two to four pages.

Table 8-37 provides an exemplar of the minimum level of content and detail required.

Table 8-47 Emergency Preparedness Staffing and Qualifications

Role	Incident Type	Responsibilities	Qualifications	# of Dedicated Staff Required	# of Dedicated Staff Provided	# of Contract Workers	# of Contract Workers

						Required	**Provided**
President		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.	38 years of engineering and technical experience with electrical power systems including field inspections of equipment	1	1		
Utility Manager		Direct emergency operations under the WMP and EDRP; Ensure monitoring of weather forecasts and conditions is conducted by staff; Direct operational activities related to system line-	-BS and PE Chemical Engineer -10 years as environmental consultant conducting site inspections and project management involving a variety of environmental and safety issues -13 years of experience in general management of industrial	1	1		

		up and PSPS as warranted; Ensure Field Operations provide timely / accurate information to the Customer Service Supervisor and staff performing customer and public information functions; Closely coordinate with stakeholders leading 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; Ensure training for BVES staff	equipment used in hazardous areas				

		with identified PSPS; Ensure availability of resources to execute PSPS plan and identify gaps in resources and proposed remedies to the President; Ensure regulations are followed required reports are timely submitted to regulatory bodies, including the CPUC and Energy Safety; Evaluate whether changes to PSPS plan are warranted and implementing any necessary changes.					
Field Operations Supervisor		Monitor (or direct monitoring) weather advisories, consultant forecasts, and the	-Over 42 years in the utility industry -Journeyman Lineman -Power Troubleman	1	1		

		NFDRS forecast at least daily during fire season; Direct and manage operational system line-ups based on conditions as described in PSPS plan; Direct and coordinate PSPS procedures; Direct the activities of the WRT; Control all switch and system lineup operations; Provide (or ensure) timely / accurate information to the Customer Service Supervisor and/or staff performing customer / public information functions; Inform the Utility Manager of system issues; Collect data and maintain	-Line Crew Foreman -Operations Manager -Assistant General Manager of Operations				

		documentation including, but not limited to, inspections, operational system lineup, and PSPS activities; and Submit to the Utility Manager recommended changes to PSPS plan as warranted.					
Utility Engineer & Wildfire Mitigation Supervisor		Ensure system design and construction is compliant with applicable rules and regulations to mitigate fire; Develop distribution, sub-transmission and substations designs to reduce fire risk; Research, evaluate, and source materials fire resistant materials and equipment;	-13 years as an Electrical Engineer -Eight Years with BVES as substation designer, transmission/distribution designer and compliance engineer	1	1		

		Develop device protective settings and select fuses to prevent fire while taking into account reliability and load; Support Field Operations and the WRT as directed by the Utility Manager in the execution of system operations; and Submit recommended changes to the Utility Manager as warranted.					
Customer Program Specialist		Notify (or direct to notify) local government, agency, and customer notifications; Establish and maintain customer communications methods and equipment to support PSPS		1	1		

		notifications; Train staff assigned to issue customer / public information via media notification statements and customer communications methods; Develop (or cause to be developed) the contact list of stakeholders; 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 PSPS plan as warranted.					

Personnel Training

The electrical corporation must report on its internal personnel training program(s) for wildfire and PSPS emergency events. This training must include, at a minimum, training on relevant policies, practices, and procedures before, during, and after a wildfire or PSPS event. The reporting must include, at a minimum:

- *The name of each training program*
- *A brief narrative on the purpose and scope of each program*
- *The type of training method*
- *The schedule and frequency of training programs*
- *The percentage of staff who have completed the most current training program*
- *How the electrical corporation tracks who has completed the training programs*

Table 8-39 provides an example of the minimum acceptable level of information.

BVES meets internally at least twice per year to train and review the EDRP and PSPS Plans and procedures. In addition, the entire management and a majority of the BVES staff is involved with both PSPS tabletop and functional exercises. During these exercises, BVES runs through scenarios where PSPS de-energization is simulated.

In addition, BVES conducts a monthly Safety Committee Meeting which includes management as well as key office and field personnel. This meeting addresses safety and emergency response concerns that can be raised by any of the committee members. Emergency planning, wildfire, and PSPS are commonly discussed during the meetings. Minutes for each safety meeting are maintained.

BVES conducts a monthly training class for emergency situations and for general safety for working in the office and in the field. These training classes provide the background for all BVES employees to understand how to address an emergency situation, if encountered. Sign-in sheets are utilized to track employee participation for all training classes. Mandatory Safety training courses for 2023 are listed in Table 8-39. Exemplar of Electrical Corporation Personnel Training Program

External Contractor Training

The electrical corporation must report on its external contractor training program(s) for wildfire and PSPS emergency events. This training must include, at a minimum, training on relevant policies, practices, and procedures before, during, and after a wildfire or PSPS event. The reporting must include, at a minimum:

- *The name of each training program*
- *A brief narrative on the purpose and scope of each program*
- *The type of training method*
- *The schedule and frequency of training programs*
- *The percentage of contractors who have completed the most current training program*
- *How the electrical corporation tracks who has completed the training programs*

Table 8-39 provides an example of the minimum acceptable level of information.

Wildfire and PSPS activation/response is managed by BVES staff. Any contractor used in a wildfire or PSPS event is fully trained for emergency response. BVES meets with its utility construction and tree service contractors on a weekly basis to review safety and/or emergency protocols. In the event of an emergency or PSPS event, BVES meets with our contractors to determine lessons learned. If there are no wildfire or emergencies, then BVES will meet with contractors e times per year to discuss emergency situations. In 2023, BVES is implementing a more in-depth contractor management program which includes training for wildfire and PSPS situations.

Table 8-48 Electrical Corporation Personnel Training Program

Training Topic	Purpose and Scope	Training Method	Training Frequency	Position or Title of Personnel Required to Take Training	# of Personnel Requiring Training	# of Personnel Proved with Training	Form of Verification or Reference
Fire Safety		In person or online for all training classes	As required, yearly, or every other year	All staff	~ 45		Sign in sheets used for all training classes
Office Safety				All Staff	~45		
Ergonomics				All Staff	~45		
Emergency Action Plan				All Staff	~45		
Hazardous Communications				All Staff	~45		
Heat/Cold Stress				All Staff	~45		
Injury and Illness Prevention				All Staff	~45		
Personal Protective Equipment				Field Operations and Management	~20		
Tool Safety				Field Operations and Management	~20		

Trenching, Shoring, and Excavation				Field Operations and Management	~20		
Confined Space Entry				Field Operations and Management	~20		
Lockout/Tagout				Field Operations and Management	~20		
Electrical Safety				Field Operations and Management	~20		
Ergonomics				Field Operations and Management	~20		
Roadway Worker				Field Operations and Management	~20		
Traffic Control and Flagging				Field Operations and Management	~20		

Table 8-49 Contractor Training Program

Program in development as stated above

Training Topic	Purpose and Scope	Training Method	Training Frequency	Position or Title of Personnel Required to Take Training	# of Contractors Requiring Training	# of Contractors Proved with Training	Form of Verification or Reference

8.4.2.3 8Drills, Simulations, and Tabletop Exercises

Discussion-based and operational-based exercises enhance knowledge of plans, allow personnel to improve their own performance, and identify opportunities to improve capabilities to respond to real wildfire emergency events and PSPS events. Exercises also provide a method to evaluate a electrical corporation's emergency preparedness plan and identify planning and/or procedural deficiencies.

Internal Exercises

The electrical corporation must report on its program(s) for conducting internal discussion-based and operations-based exercises for both wildfire and PSPS emergency events. This must include, at a minimum, the types of discussion-based exercises (e.g., seminars, workshops, tabletop exercises, games) and operations-based exercises (e.g., drills, functional exercises, full-scale exercises), the purpose of the exercises, the frequency of internal exercise programs, the percentage of staff who have completed/participated in exercises and means for verification of internal exercises.

An exemplar of the minimum acceptable level of information is provided in Table 8-40.

External Exercises

The electrical corporation must report on its program(s) for conducting external discussion-based and operations-based exercises for both wildfire and PSPS emergency events. This must include, at a minimum, the types of discussion-based exercises (e.g., seminars, workshops, tabletop exercises, games) and operations-based exercises (e.g., drills, functional exercises, full-scale exercises), the schedule and frequency of external exercise programs, the percentage of public safety partners who have participated in these exercises and means for verification of external exercises.

An exemplar of the minimum acceptable level of information is provided in Table 8-41.

Table 8-50 Internal Drill, Simulation, and Tabletop Exercise Program

Exercise Title and Type	Purpose	Exercise Frequency	Position or Title of Personnel Required to Participate	# of Personnel Participation Required	# of Personnel Participation Completed	Form of Verification or Reference

Internal TTE	Test PSPS Capabilities	Annual	*President*	*N/A*	*N/A*	Post-Season Report
			Field Operations Supervisor Utility Engineer & Wildfire Supervisor	*N/A*	*N/A*	
			Customer Program Specialist	*N/A*	*N/A*	
			Accounting Supervisor	*N/A*	*N/A*	
			Logistic Group Leader	*N/A*	*N/A*	
			Others as required	*N/A*	*N/A*	
Internal Functional Exercise	Test PSPS Capabilities	Annual	*President*	*N/A*	*N/A*	Post-Season Report
			Utility Manager	*N/A*	*N/A*	
			Field Operations Supervisor	*N/A*	*N/A*	
			Utility Engineer &	*N/A*	*N/A*	

			Wildfire Supervisor			
			Customer Program Specialist	*N/A*	*N/A*	
			Accounting Supervisor	*N/A*	*N/A*	
			Logistic Group Leader	*N/A*	*N/A*	

BVES conducts at least one tabletop and one functional simulation exercise annually. These exercises involve participating stakeholders from the Big Bear community and be coordinated with CPUC Cal Fire, Cal OES, communication providers, AFN representatives, and other public safety partners. Additionally, BVES coordinates with these stakeholders to develop and plan the exercises. The exercises seek to prepare BVES and its community partners for a PSPS and enhance their performance, communication protocols, notification practices, and restoration procedures and test the functionality of the plan to the extent practicable. BVES keeps detailed records of these plans and submit reports of these exercises to the CPUC as required. BVES review the exercises to identify strengths and weaknesses of BVES actions and seek to incorporate lessons learned into the PSPS Plan and other associated documentation, as appropriate.

Table 8-51 External Drill, Simulation, and Tabletop Exercise Program

Category	***Exercise Title and Type***	***Purpose***	***Exercise Frequency***	***Position or Title of Personnel Required to Participate***	***# of Personnel Participation Required***	***# of Personnel Participation Completed***	***Form of Verification or Reference***
	Table Top	*Wildfire and PSPS Preparation*	*Once per year*	*President*	*X*	*X*	*Exercise reported to the CPUC*

				Utility Manager	*X*	*X*	
				Field Operations Supervisor Utility Engineer & Wildfire Supervisor	*X*	*X*	
				Customer Program Specialist	*X*	*X*	
				Accounting Supervisor	*X*	*X*	
				Logistic Group Leader	*X*	*X*	
				Others as required			
	Functional	*Wildfire and PSPS Preparation*	*Once per year*	*President*	*X*	*X*	*Exercise reported to the CPUC*
				Utility Manager	*X*	*X*	
				Field Operations Supervisor	*X*	*X*	
				Utility Engineer	*X*	*X*	

				& Wildfire Supervisor			
				Customer Program Specialist	*X*	*X*	
				Accounting Supervisor	*X*	*X*	
				Logistic Group Leader	*X*	*X*	
				Others as required	*X*	*X*	

8.4.2.4 Schedule for Updating and Revising Plan

The electrical corporation must provide a log of the updates to its emergency preparedness plan since 2019 and the date of its next planned update.

Updates should occur every two years, per R.15-06-009 and D.21-05-019. For each update, the electrical corporation must provide the following:

- *Year of updated plan*
- *Revision type (e.g., addition, modification, elimination)*
- *Component modified (e.g., communications, training, drills/exercises, protocols/procedures, MOAs)*
- *A brief description of the lesson learned that informed the revision*
- *A brief description of the specific addition, modification, or elimination*

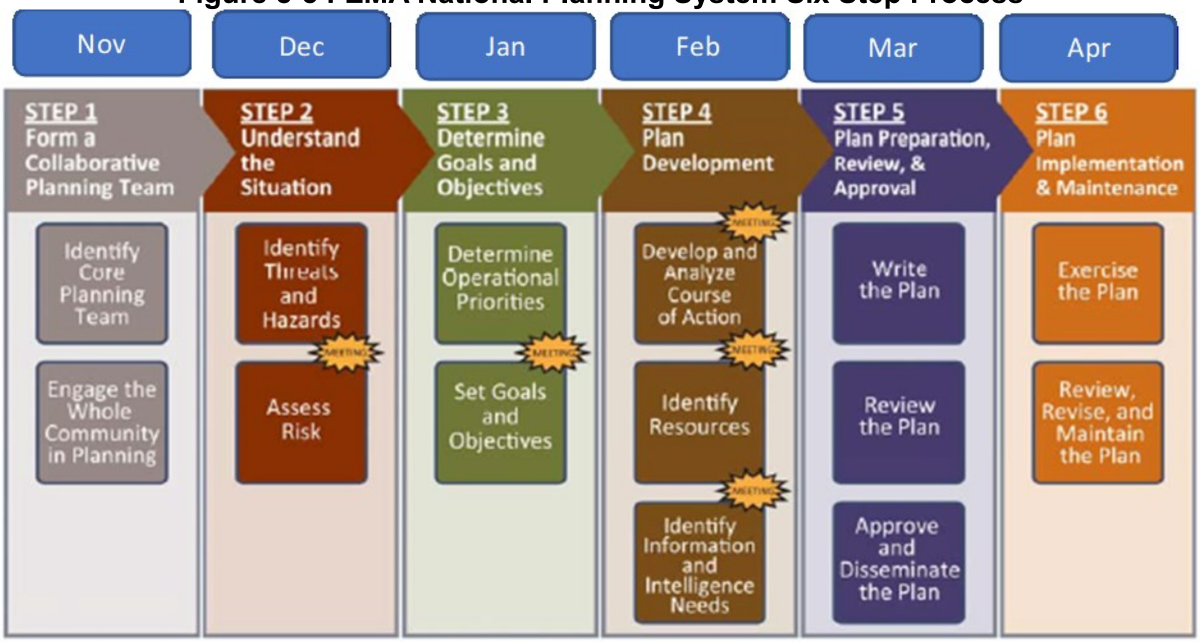
An exemplar of the minimum acceptable level of information is provided in Table 8-42.

BVES has not identified any specific future improvements at this time. Each year the ERDP is reviewed and updated as applicable due to changes in requirements, lessons learned, changes to the grid, and suggestions from stakeholders in the community. For example, once the Radford Line is completed, BVES will update its ERDP to reflect the new capabilities of the Radford Line (e.g., not de-energizing it from April to October).

Bear Valley leverages the protocols included in the EDRP to learn from wildfire events in the same manner the utility learns from any emergency event. The criticality and scope of the BVES EDRP has grown over the past few years as extreme weather events become more common. To meet these challenges, emergency preparedness and response activities must be systematic, inclusive, and transparent to review incidents in a manner aligned with our core values.

In 2023, BVES began utilizing the FEMA National Planning System Six Step process to update the EDRP. The EDRP review begins in November and ends in April with a step performed each month: Step 1 Form a Collaborative Planning Team, Step 2, Understand the Situation, Step 3, Determine Goals and Objectives, Step 4, Plan Development, Step 5 Plan Preparation, Review and Approval, and Step 6, Plan Implementation & Maintenance. BVES will review the EDPR every year and update it as necessary. Figure 8-5 outlines the FEMA Six Step process.

Figure 8-5 FEMA National Planning System Six Step Process



For the PSPS plan, no direct lessons learned from BVES-initiated activations can be applied to this WMP Update. BVES has not met thresholds to initiate a PSPS event within 2020 through 2022. The triggering threshold has also not changed based on the implementation of WMP initiatives. In the future, BVES anticipates continued re-designation of high-risk areas to reduce risk designations after years of significant WMP initiative implementation. As mitigations are deployed and real-time modeling capabilities are enhanced, BVES will re-evaluate its PSPS trigger thresholds.

In 2022, BVES contracted with Technosylva in an effort to provide real-time situational awareness through on-demand fire spread predictions and impact analysis, wildfire risk forecasting for customer assets and the service area using daily weather prediction integration and asset risk analysis using historical weather climatology. Additional quantitative analysis of this projected evolution will be available over the year with full deployment in 2023.

In mid-2022, BVES is updating its current PSPS Plan and Protocols to align with Phase 3 de-energization guidelines issued under D. 21-06-034.

BVES has not initiated any PSPS events over the past three years and does not forecast an imminent need to de-energize in the future based on a one, three, or ten-year forecast.

Table 8-52 Wildfire-Specific Updates to the Emergency Preparedness Plan

ID #	Year of Updated Plan	Revision Type	Lesson Learned	Revision Description	Reference Section
Emergency Response and Disaster Plan (EDRP), dated March 31, 2022	2023	Modification	Follow plan as outlined, ensure emergency equipment is in working condition		
Public Safety Power Shutdown Plan dated January 31, 2023	2025	Modification	None, no PSPS in territory		

8.4.3 External Collaboration and Coordination

8.4.3.1 Emergency Planning

In this section, the electrical corporation must provide a high-level description of its wildfire and PSPS emergency preparedness coordination with relevant public safety partners at state, county, city, and tribal levels within its service territory. The electrical corporation must indicate if its coordination efforts follow California's SEMS or, where relevant for multi-jurisdictional electrical corporations (e.g., PacifiCorp), the Federal Emergency Management Agency (FEMA) National Incident Management Systems (NIMS), as permitted by GO 166. The description must be no more than a page.

In addition, the electrical corporation must provide the following information in tabular form, with no more than one page of information in the main body of the WMP and the full table in Appendix B:

- *List of relevant state, city, county, and tribal agencies within the electrical corporation's service territory and key point(s) of contact, with associated contact information. Where necessary, contact information can be redacted for the public version of the WMP.*
- *For each agency, whether the agency has provided consultation and/or verbal or written comments in preparation of the most current wildfire- and PSPS-specific emergency preparedness plan. If so, the electrical corporation should provide the date, time, and location of the meeting at which the agency's feedback was received.*
- *For each agency, whether it has an MOA with the electrical corporation on wildfire and/or PSPS emergency preparedness, response, and recovery activities. The electrical corporation must provide a brief summary of the MOA, including the agreed role(s) and responsibilities of the external agency before, during, and after a wildfire or PSPS emergency.*
- *In a separate table, a list of current gaps and limitations in the electrical corporation's existing collaboration efforts with relevant state, county, city, and tribal agencies within its territory. Where gaps or limitations exist, the electrical corporation must indicate the remedial action plan and timeline for resolving.*
- *For all requested information, a form of verification that can be provided upon request for compliance assurance.*

Reference the Utility Initiative Tracking ID where appropriate.

Table 8-44 and Table 8-45 provide exemplars of the minimum level of content and detail required.

Table 8-53 State and Local Agency Collaboration(s)

Name of State or Local Agency	Point of Contact and Information	Emergency Preparedness Plan Collaboration – Last version of Plan Agency Collaborated	Emergency Preparedness Plan Collaborative Role	Memorandum of Agreement (MOA)	Brief Description of MOA
CPUC	Drucilla.Dunton@cpuc.ca.gov				
San Bernardina County	Sbcoa@oes.sbcounty.gov				
Big Bear Fire	jeff.willis@bigbearfire.org			Mountain Mutual Aid	Refer to Section 8.4.3.3
San Bernardino Fire	dmunsey@sbcfire.org			Mountain Mutual Aid	Refer to Section 8.4.3.3
CAL FIRE	bdueccstaff@fire.ca.gov				
U.S. Forest Service	Travis.Mason@usda.gov				
San Bernardino County School District	rncollins@sbcsd.org				
California Highway Patrol	NASalais@chp.ca.gov			Mountain Mutual Aid	Refer to Section 8.4.3.3
California Department of Transportation	emily.leinen@dot.ca.gov			Mountain Mutual Aid	Refer to Section 8.4.3.3

Big Bear Area Regional Wastewater Agency	jshimmin@bbarwa.org			Mountain Mutual Aid	Refer to Section 8.4.3.3
Big Bear City Community Service Division	mreeves@bbccsd.org			Mountain Mutual Aid	Refer to Section 8.4.3.3
Big Bear Lake Department of Water and Power	swilson@bbldwp.com			Mountain Mutual Aid	Refer to Section 8.4.3.3
Big Bear Municipal Water District	mstephenson@bbmwd.net			Mountain Mutual Aid	Refer to Section 8.4.3.3
Bear Valley Community Healthcare District	John.McKinney@bvchd.com			Mountain Mutual Aid	Refer to Section 8.4.3.3
Bear Valley Unified School District	mary_suzuki@bearvalleyusd.org				
Big Bear Chamber of Commerce	execdir@bigbearchamber.com				
Big Bear Airport Authority	jmelissa@flybigbear.com			Mountain Mutual Aid	Refer to Section 8.4.3.3
Big Bear Mountain Rescue	mburnett@bbmr.com			Mountain Mutual Aid	Refer to Section 8.4.3.3
Bear Valley Hospice	admin@bearvalleyhospice.com			Mountain Mutual Aid	Refer to Section 8.4.3.3

AT&T	EM357C@att.com				
City of Big Bear Lake	ssullivan@citybigbearlake.com				
City of Big Bear Lake	Jmathieo@Cityofbigbearlake.com			Mountain Mutual Aid	Refer to Section 8.4.3.3
San Bernardino Office of Emergency Services	Daniel.Munoz@oes.sbcounty.gov				
Big Bear Fire	mmaltby@bigbearfire.org				
CAL FIRE	BDUCommandStaff@fire.ca.gov				
U.S. Forest Service	scott.a.evans@usda.gov				
San Bernardino County School District	mdattilo@sbcsd.org				
California Highway Patrol	JGriede@chp.ca.gov				
Big Bear Area Water Authority	tbemisdarfer@bbarwa.org				
Big Bear Community Service District	jgriffith@bbccsd.org				
Big Bear Lake Department of Water and Power	jhall@bbldwp.com				

Big Bear Municipal Water District	tbowman@bbmwd.net			Mountain Mutual Aid	Refer to Section 8.4.3.3
Southwest Gas	phillip.petteruto@swgas.com			Mountain Mutual Aid	Refer to Section 8.4.3.3
Bear Valley Community Healthcare Division	megan.meadors@bvchd.com				
Bear Valley Unified School District	linda_rosado@bearvalleyusd.org				
Big Bear Airport Authority	rgoss@flybigbear.com			Mountain Mutual Aid	Refer to Section 8.4.3.3
Big Bear Mountain Rescue	bburke@bbmr.com			Mountain Mutual Aid	Refer to Section 8.4.3.3
Bear Valley Hospice	info@bearvalleyhospice.com			Mountain Mutual Aid	Refer to Section 8.4.3.3
AT&T	RS4669@att.com				
OEIS	kevin.miller@energysafety.ca.gov				
OEIS	melissa.semcer@energysafety.ca.gov				
Randle Communications	nrodriguez@randlecommunications.com				
CAL FIRE	frank.bigelow@fire.ca.gov				
CAL FIRE	jeff.fuentes@fire.ca.gov				
California Office of	Patricia.Utterback@CalOES.ca.gov				

Emergency Services					
California Office of Emergency Services	karen.valencia@caloes.ca.gov				
California Office of Emergency Services	michael.massone@caloes.ca.gov				
California Office of Emergency Services	thomas.graham@caloes.ca.gov				
CAL FIRE	Stephen.Volmer@fire.ca.gov				
CAL FIRE	Mark.Hillskotter@fire.ca.gov				
California Office of Emergency Services	Amanda.Moyer@CalOES.ca.gov				
CPUC	pspsnotification@cpuc.ca.gov				

Table 8-54 Key Gaps and Limitations in Collaboration Activities with State and Local Agencies

Gap or Limitation Subject	Remedial Brief Description	Remedial Action Plan
Not known at this time	N/A	N/A

8.4.3.2 Communication Strategy with Public Safety Partners

The electrical corporation must describe at a high level its communication strategy to inform external public safety partners and other interconnected electrical corporation partners of wildfire, PSPS, and re-energization events as required by GO 166 and Public Utilities Code section 768.6. This must include a brief description of the policies, practices, and procedures the electrical corporation adopts to establish appropriate communication protocols with public safety partners for both wildfire- and PSPS-specific incidents to ensure timely, accurate, and complete communications. The electrical corporation must refer to its emergency preparedness plan, as needed, to provide more detail. The narrative must be no more than two pages.

As each public safety partner will have its own unique communication protocols, procedures, and systems, the electrical corporation must coordinate with each entity individually. The electrical corporation must summarize the following information in tabulated format:

- *All relevant public safety partner groups (e.g., fire, law enforcement, OES, municipal governments, Energy Safety, CPUC, other electrical corporations) at every level of administration (state, county, city, or tribe), as needed.*
- *The names of individual public safety entities.*
- *For each entity, the point of contact for emergency communications coordination, and the contact information. Information may be redacted as needed.*
- *Key protocols for ensuring the necessary level of voice and data communications (e.g., interoperability channels, methods for information exchange, format for each data typology, communication capabilities, data management systems, backup systems, common alerting protocols, messaging), and associated references in the emergency plan for more details.*
- *Frequency of prearranged communication review and updates.*
- *Date of last discussion-based or operations-based exercise(s) on public safety partner communication.*

In a separate table, the electrical corporation must list the current gaps and limitations in its public safety partner communication strategy coordination. Where gaps or limitations exist, the electrical corporation must indicate the remedial action plan and timeline for resolving. For all requested information, the electrical corporation must indicate a form of verification that can be provided upon request for compliance assurance.

Table 8-46 and Table 8-47 provide exemplars of the minimum level of content and detail required.

Table 8-55 High-Level Communication Protocols, Procedures, and Systems with Public Safety Partners

Public Safety Partner Group	Name of Entity	Point of Contract and Information	Key Protocols	Frequency of Prearranged Communication Review and Update	Communication Exercise(s): Date of Last Completed	Communication Exercise(s): Date of Planned Next
Law enforcement	Sheriff's Department Big Bear Lake Patrol Station	Lt. Kelly Craig Lieutenant 909-420-5620 kcraig@sbcsd.org		Quarterly Updates and Planned Exercises	March 1, 2023	April 13, 2023 PSPS Tabletop Exercise
Medical	Bear Valley Community Hospital	John P. McKinney MPT Director of Physical Therapy/PIO 909-744-2231 John.mckinney@bvchd.com		Quarterly Updates and Planned Exercises		
	Bear Valley Hospice	Cary Stewart 949-338-7252		Quarterly Updates		

		admin@bearvalleyhospice.com				
Fire department	Big Bear Fire Department Headquarters – Station 281 41090 Big Bear Blvd	Jeff Willis Fire Chief 909-731-4824 Jeff.willis@bigbearfire.org		Quarterly Updates and Planned Exercises	March 1, 2023	April 13, 2023 PSPS Tabletop Exercise
City & County Facilities	City of Big Bear Lake City Hall (includes Emergency Operations Center)	Erik Sund City Manager 909-633-4011 sund@citybigbearlake.com		Quarterly Updates and Planned Exercises	March 1, 2023	April 13, 2023 PSPS Tabletop Exercise
Communications Providers	Verizon Wireless	Chris Sinner 714-669-3535 Chris.sinner@verisonwireless.com		Quarterly Updates	March 1, 2023	April 13, 2023 PSPS Tabletop Exercise
		Jane Whang 415-778-1022 Jane.whang@verizon.com				
		Rex Knowles 801-514-0589 Rex.knowles@verizon.com				
	AT&T Wireless	Kevin Quinn 818-731-4000 Kq8185@att.com				
		Joshua Overton 209-406-6712 Jo2147@att.com				

		Joshua Mathisen Jm6547@att.com				
		John Goddard Jg266@att.com				
	Frontier California Inc.	Bret Plaskey 909-748-7880 Bret.p.plaskey@ftr.com				
		Charlie Born 916-686-3570 Charlie.born@ftr.com				
	Sprint	Jake Osorio 808-317-0276 SPR-inspections@motive-energy.com				
	Charter Communications	Robert Fisher 760-674-5404 Robert.fisher@charter.com				
		Lynn Notarianni 720-518-2585 Lynn.notariani@charter.com				
		Dan Gonzalez Dan.gonzales@charter.com				
	T-Mobile	Saif Abdullah 714-757-7075 Saif.abdullah@t-mobile.com				
		Steve Kukta				

		414-572-8358 Stephen.h.kukta@t-mobile.com				
Radio Stations	KBHR	Cathy Herrick 909-499-4825 cathy@kbhr933.com				
Utilities	City of Big Bear Lake Department of Water	Danny Ent 909-816-7709 dent@bbldwp.com		Quarterly Updates		
	Big Bear Area Regional Wastewater Agency (BBARWA)	John Shimmin 760-808-1256 jshimmin@bbarwa.org		Quarterly Updates		
	Big Bear City Community Services Department (CSD)	Mary Reeves 909-936-9521 mreeves@bbccsd.org				
	Edison (SCE)	Bryan Falconer Account Manager 626-826-3745 Bryan.falconer@sce.com		Quarterly Updates and External Planned Exercises		
	South West Gas (SWG)	Phillip Petteruto Superintendent Operations 909-366-4869 Phillip.petteruto@swgas.com				
		SWG Dispatch 877-860-6020				

		snvdispatch@swgas.com				
	Big Bear Municipal Water District (MWD)	Mike Stephenson General Manager 909-289-5157 mstephenson@bbmwd.net				
Airports	Big Bear Airport District	John Melissa 909-904-7700 jmelissa@flybigbear.com		As Needed	N/A	N/A
Schools	Bear Valley Unified School District	Dr. Mary Suzuki Superintendent of schools 909-638-6851 Mary_suzuki@bearvalleyusd.org		As Needed	N/A	N/A
Resorts	Big Bear Mountain Resorts	Mart Burnett Sr. Director Facilities 909-725-4017 mburnett@bbmr.com		As Needed	N/A	N/A

Table 8-56 Key Gaps and Limitations in Communication Coordination with Public Safety Partners

Gap or Limitation Subject	Remedial Brief Description	Remedial Action Plan
No known gaps at this time	N/A	N/A

8.4.3.3 Mutual Aid Agreements

In this section, the electrical corporation must provide a brief overview of the Mutual Aid Agreements (MAA) it has entered regarding wildfire emergencies and/or disasters, as well as PSPS events. The overview narrative must be no more than one page.

In addition, the electrical corporation must provide the following wildfire emergency information in tabulated format:

- *List of entities with which the electrical corporation has entered a MAA*
- *Scope of the MAA*
- *Resources available from the MAA partner*

Mutual Aid Agreements are an efficient and effective resource multiplier available to BVES restoration efforts. It is extremely important that these agreements be maintained and staff understand what resources they may provide and how to request the resources.

California Utilities Emergency Association: The California Utilities Emergency Association (CUEA) Mutual Aid Agreement allows member utilities to request and obtain labor, materials, 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.

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 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 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. Bear Valley Electric Service, Inc. EDRP Page 31 of 65 states 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 8-48 provides an exemplar of the minimum level of content and detail required.

Table 8-57 High-Level Mutual Aid Agreement for Resources During a Wildfire or De-Energization Incident

Mutual Aid Partner	Scope of Mutual Aid Agreement	Available Resources from Mutual Aid Partner
Mountain Mutual Aid Association • 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	Share information, resources, and manpower in case of an emergency	Information, manpower, and resources

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 Resources available from the MAA partner		

8.4.4 Public Emergency Communication Strategy

The electrical corporation must describe at a high level its comprehensive communication strategy to inform essential customers and other community stakeholder groups of wildfires, outages due to wildfires, and PSPS and service restoration, as required by Public Utilities Code section 768.6. This should include a discussion on the policies, practices, and procedures the electrical corporation adopts to establish appropriate communication protocols to ensure timely, accurate, and complete communications. The electrical corporation may refer to its Public Utilities Code section 768.6 emergency preparedness plan to provide more detail. The narrative must be no more than one page.

In the following sections, the electrical corporation must provide an overview of the following components of an effective and comprehensive communication strategy:

- *Protocols for emergency communications*
- *Messaging*
- *Current gaps and limitations*

Reference the Utility Initiative Tracking ID where appropriate.

Community outreach, public awareness, and communications efforts are required to reduce the impact to customers and the community from an event causing interrupting of service and/or poses serious public risks. Effective planning and awareness also assist to limit the scope of extreme events and avoid escalation. BVES altered how the company addressed the risk of catastrophic wildfires due to the increased presence of potential wildfire due to climate changes and environmental conditions. BVES works year-round to educate customers and the public and works with community partners to improve outreach, awareness, and communications.

The Energy Resource Manager oversees communications plans and activities. Reporting to the energy Resource Manager is the Customer Service Supervisor, who manages communication activities. BVES's communication plan includes a two-pronged approach (1) proactive preparation before emergencies occur and (2) notifications during and after emergency events. Communications protocols vary slightly when dealing with stakeholders that include customers, first responders, the local mutual aid association, local government, among other key stakeholders.

The list below describes the goals and methods of informing each of these groups.

Customer Outreach and Notifications: The goal of customer outreach is to educate and prepare customers for fire prevention, proactive de-energization, and other utility infrastructure-related emergencies. Communication formats are planned in English, Spanish, Tagalog, Vietnamese, Chinese, French, Mixteco and Zapoteco for online resources and when requested by customers. BVES is continuing to enhance its community outreach activities and has conducted a self-identified survey process to account for these populations. Indigenous communities surrounding the service area are investigated to account for the unique languages representing

English as a Second Language (ESL) speakers. BVES collaborates with other community organizations to assure that a local community resource center is available to customers during emergencies. BVES aligns its communication with other organizations, so it is clear and consistent among the local and state organizations.

Before Emergencies: Proactive outreach includes regular messages related to fire prevention (such as vegetation management, distribution inspection, and de-energization policies) and operational initiatives. This occurs through public workshops, BVES newsletters, social media, website posts, and other forms of media. Special presentations related to fire prevention and preparing for emergencies, including PSPS events, are provided through multiple outlets, including printed material, public service announcements, social media, and special briefings by BVES.

During / After Emergencies: Notifications include BVES-prepared customer-facing statements for staff to disseminate in the case of de-energization and emergencies, including information about timing and location of such events. These notifications occur through news outlets, printed materials, digital media, radio forums, website updates, social media updates, text messages, local government, and agency media (e.g., City of Big Bear Lake's email blasts), and interactive voice response (IVR) calls. Additional forms of communication may be leveraged as new technologies and software become available.

Post-event, BVES provides billing and repair support for affected customers. Billing support may include billing adjustments, deposit waivers, suspension of disconnection, and extended payment plans for standard and low-income customers. Repair support may include regular communications about repair processing and timing and individualized support from a utility representative.

1. **Local Government and Agency Engagement and Notification**: Communications with local government agencies is essential to BVES's outage and emergency response plans. BVES leadership strives to engage with local agencies in a direct and expedient manner. Coordination and preparation for emergencies, including 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 PSPS. BVES prepares and informs relevant agencies, before, during, and after outages, PSPS, or emergencies. BVES's protocols include establishing a two-way communication channel to help facilitate communications to collaboratively manage the potential impacts of events.

    a. Before Emergencies: BVES participates in proactive briefings with the local government to collaboratively plan to minimize the impacts of potential emergencies. These briefings include in-person meetings, emails, and coordinated training and drills. BVES solicits feedback from the local government and other agencies on its emergency preparedness communication plans and protocols, to incorporate ongoing improvements.

    b. During / After Emergencies: When an emergency occurs, BVES notifies all relevant local government and agencies immediately to ensure proper response coordination. The Customer Care & Operations Support Supervisor and other staff performing customer and public information functions work closely to coordinate with counterparts including the local government and other agencies, providing outage and emergency notifications, estimated time to restore service, and periodic updates as available. BVES continues to provide timely communications to all parties until the situation has been resolved. These notifications happen through phone, text, email and in-person communications.

2. **Mountain Mutual Aid Association (MMAA) Participation**: The MMAA works in conjunction with the local fire department. BVES's outreach and engagement with the MMAA is similar to the collaborative approach used with local government and agency communications. Specifically, the goal is to inform, prepare, and coordinate closely with community first responders and aid workers.

    a. Before Emergencies: Proactive briefings center on how the plan impacts the surrounding community based on BVES's utility infrastructure. Briefings may be conducted through email, training, remote collaboration tools, and in-person meetings, among others. BVES gains valuable feedback from MMAA to harmonize its emergency preparedness, communication plans, and overall protocols to align with other community partners aligned in their goal of public safety.

    b. During / After Emergencies: When an emergency occurs, BVES notifies MMAA members immediately to effectuate a coordinated response. BVES continues to provide timely communications and participate in coordinated activities until the situation has been resolved. Communication and notifications happen through phone, text, email and in-person communications, among others.

3. **CPUC Reporting**: BVES's communication with the CPUC aligns with mandates and requirements.

    a. Before Emergencies: BVES submits its Fire Prevention Plan, WMP, and EDRP, and PSPS Plans for review and input. All plans are designed to work together to minimize the impact of outages and infrastructure-related events and, most importantly, protect the public safety.

    b. During / After Emergencies: BVES notifies the Director of Safety Enforcement Division (SED) within 12 hours of the power being shut off. BVES also notifies the CPUC and Warning Center at the Office of Emergency Services in San Bernardino within one hour of shutting off the power if the outage meets the major outage criteria of GO 166.

BVES provides a written report to the Director of SED no later than 10 business days after a shut-off event ends per ESRB-8. The utility complies with all analysis and report requests during and after any emergencies. Outage data shall also be included in BVES's annual reliability indices report to the CPUC.

BVES engages in this activity to verify that the programs they have developed and the tools that are being used are at an equivalent or higher level to its California counterparts as well as its counterparts outside of the state of California. BVES is implementing a strategy and preparing actions to engage with agencies outside of California to exchange best practices both for utility wildfire mitigation and for stakeholder cooperation to mitigate and respond to wildfires.

8.4.4.1 Protocols for Emergency Communications

The electrical corporation must identify the relevant community stakeholder groups in its service territory and describe the protocols, practices, and procedures used to provide notification of wildfires, outages due to wildfires and PSPS, and service restoration before, during, and after each incident type. Community stakeholder groups include, but are not limited to, the general public, priority essential services, AFN populations, non-English speakers, tribes, and people in remote or isolated areas. The narrative must include a brief discussion on the decision-making process and use of best practices to ensure timely, accurate, and complete communications. The narrative must be no more than one page.

The electrical corporation must also provide, in tabular form, details of the following:

- *Methods for communicating*
- *Means to verify message receipt*

Table 8-49 provides an exemplar of the minimum level of content and detail required.

Table 8-58 Protocols for Emergency Communication to Public Stakeholder Groups

Stakeholder Group	Event Type	Method(s) for Communicating	Means to Verify Message Receipt
All Listed Above		Email	Read Receipt If read receipt not confirmed phone contact is made

Table 8-59 Category Entity Primary Contact List

Category	Entity	Primary
Law enforcement	Sheriff's Department Big Bear Lake Patrol Station	Lt. Kelly Craig Lieutenant 909-420-5620 kcraig@sbcsd.org
Medical	Bear Valley Community Hospital	John P. McKinney MPT Director of Physical Therapy/PIO 909-744-2231 John.mckinney@bvchd.com
	Bear Valley Hospice	Cary Steward 949-338-7252 admin@bearvalleyhospice.com
Fire Department	Big Bear Fire Department Headquarters- Station 281 41090 Big Bear Blvd	Jeff Willis Fire Chief 909-731-4825 Jeff.willis@bigbearfire.org
City & County Facilities	City of Big Bear Lake City Hall (includes Emergency Operations Center)	Jeff Mathieu Interim City Manager 909-633-1575 jeffmathieu@citybigbearlake.com
Communications providers	Verizon Wireless	Chris Sinner 714-669-3535 Chris.sinner@verizonwireless.com
		Jane Whang 415-778-1022 Jane.whang@verizon.com
	AT&T Wireless	Kevin Quinn

		818-731-4000 Kq8185@att.com
		Joshua Overton 209-406-6712 Jo2147@att.com
		Joshua Mathisen Jm6347@att.com
		John Goddard Jg266q@att.com
	Frontier California Inc.	Bret Plaskey 909-748-7880 Bret.p.plaskey@ftr.com
		Charlie Born 916-686-3570 Charlie.born@ftr.com
	Sprint	Jake Osorio 818-317-0276 SPR-Inspections@motive-energy.com
	Charter Communications	Robert Fisher 760-674-5404 Robert.fisher@charter.com
		Lynn Notarianni 720-518-2585 Lynn.notariani@charter.com
		Dan Gonzalez Dan.gonzales@charter.com
	T-Mobile	Saif Abdullah 714-757-7075 Saif.abdullah@t-mobile.com
		Steve Kukta 414-572-8358 Stephen.H.kukta@t-mobile.com
		Vivek Kurisunkal Vivek.kurisunkal@t-mobile.com
Radio stations	KBHR	Cathy Herrick 9099-499-4825 Cathy@kbhr933.com
Utilities	City of Big Bear Lake Department of Water	Danny Ent 909-816-7709 dent@bbldwp.com
	Big Bear Area Regional Wastewater Agency (BBARWA)	John Shimmin 760-808-1256 jshimmin@bbarwa.org
	Big Bear City Community Services Department (CSD)	Mary Reeves 909-936-9521 mreeves@bbccsd.org
	Edison (SCE)	Bryan Falconer Account Manager

		626082603745 Bryan.falconer@sce.com
	South West Gas (SWG)	Phillip Petteruto Superintendent Operations 909-366-4869 Phillip.petteruto@swgas.com
		SWG Dispatch 877-760-6020 snvdispatch@swgas.com
	Big Bear Municipal Water District (MWD)	Mike Stephenson General Manager 909-289-5157 mstephenson@bbmwd.net
Airports	Big Bear Airport District	John Melissa 909-904-7700 jmelissa@flybigbear.com
Schools	Bear Valley Unified School District	Dr. Mary Suzuki Superintendent of Schools 909-638-6851 Mary_suzuki@bearvalleyusd.org
Resorts	Big Bear Mountain Resorts	Mark Burnett Sr. Director Facilities 909-725-4017 mburnett@bbmr.com

8.4.4.2 Messaging

In this section, the electrical corporation must describe its process and approach for developing effective messaging to reach the largest percentage of public stakeholders in its service territory before, during, and after a wildfire, an outage due to wildfire, or a PSPS event.

In addition, the electrical corporation must provide an overview of the development of the following aspects of its communication messaging strategy:

- *Features to maximize accessibility of the messaging (e.g., font size, color analyzer)*
- *Alert and notification schedules*
- *Translation of notifications*
- *Messaging tone and language that is specific, consistent, confident, clear, and accurate*
- *Key components and order of messaging content (e.g., hazard, location, time)*

The narrative must be no more than one page.

Due to the significant impact a wildfire or PSPS event may have on the community and customers, early and accurate communications must be conducted throughout the 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 allow stakeholders to take preparatory actions to mitigate the impact of a PSPS event. It is also understood the importance of hosting community workshops to allow for community members to understand the process leading to a wildfire or PSPS event. BVES hosts exercises and workshops with community to better prepare customers for a wildfire or 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 PSPS event.

8.4.4.3 Current Gaps and Limitations

In tabulated format, the electrical corporation must provide a list of current gaps and limitations in its public communication strategy. Where gaps or limitations exist, the electrical corporation must indicate the remedial action plan and timeline for resolving. For all requested information, the electrical corporation should indicate a form of verification that can be provided upon request for compliance assurance. Table 8-49 provides an exemplar of the minimum level of content and detail required.

Table 8-60 Key Gaps and Limitations in Public Emergency Communication Strategy

Gap or Limitation Subject	Remedial Brief Description	Remedial Action Plan
No known gaps at this time	N/A	N/A

8.4.5 Preparedness and Planning for Service Restoration

8.4.5.1 Overview of Service Restoration Plan

In this section of the WMP, the electrical corporation must provide an overview of its plan to restore service after an outage due to a wildfire or PSPS event. At a minimum, the overview must include a brief description of the following:

- *Purpose and scope of the restoration plan.*
- *Overview of protocols, policies, and procedures for service restoration (e.g., means and methods for assessing conditions, decision-making framework, prioritizations, degree of customization). The electrical corporation must provide an:*
- *Operational flow diagram illustrating key components of the service restoration procedures from the moment of the incident to response, recovery, and restoration of service.*
- *Resource planning and allocation (e.g., staffing, equipment).*
- *Drills, simulations, and tabletop exercises.*
- *Coordination and collaboration with public safety partners (e.g., interoperable communications).*
- *Notification of and communication to customers during and after a wildfire- or PSPS-related outage.*

The electrical corporation may refer to its Public Utilities Code section 768.6 emergency preparedness plan to provide more detail. Where the electrical corporation has already reported on the requested information in another section of the WMP, it must provide a cross-reference with hyperlink to that section. The overview must be no more than one page.

Reference the Utility Initiative Tracking ID where appropriate.

When there is a downgrade in wildfire risk and 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 that must occur before re-energization 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)

8.4.5.2 Planning and Allocation of Resources

The electrical corporation must briefly describe its methods for:

- *Planning appropriate resources (e.g., equipment, specialized workers), and*
- *Allocating those resources to assure the safety of the public during service restoration*

In addition, the electrical corporation must provide an overview of its plans for contingency measures regarding the resources required to:

- *Respond to an increased number of reports concerning unsafe conditions, and*
- *Expedite a response to a wildfire- or PSPS-related power outage*

This must include a brief narrative on how the electrical corporation:

- *Uses weather reports to pre-position manpower and equipment before anticipated severe weather that could result in an outage,*
- *Sets priorities,*
- *Facilitates internal and external communications, and*
- *Restores service*

The narrative for this section must be no more than two pages.

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:

- Level 1 (High Risk, Long-Term – more than 12 hours) EOC is fully Activated and EDRP processes implemented.
- Level 2 (Moderate Risk, Short-Term) EOC is partially activated and EDRP processes implemented.
- Level 3 (Low Risk, Short –Term) Normal Service. Crew/Dutyman and Customer Serve Processes.

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?

8.4.5.3 Drills, Simulations, and Tabletop Exercises

Discussion-based and operational-based exercises enhance knowledge of plans, allow personnel to improve their own performance, and identify opportunities to improve capabilities to respond to wildfire- and PSPS-related service outages. Exercises also provide a method to evaluate a electrical corporation's emergency preparedness plan and identify planning and/or procedural deficiencies.

Internal Exercises

The electrical corporation must report on its program(s) for conducting internal discussion-based and operations-based exercises for service restoration. This must include, at a minimum, the types of discussion-based exercises (e.g., seminars, workshops, tabletop exercises, games) and operations-based exercises (e.g., drills, functional exercises, full-scale exercises), the purpose of the exercises, the frequency of internal exercise programs, the percentage of staff who have completed/participated in exercises and means for verification of internal exercises.

- *The types of discussion-based exercises (e.g., seminars, workshops, tabletop exercises, games) and operations-based exercises (e.g., drills, functional exercises, full-scale exercises)*
- *The purpose of the exercises*
- *The schedule and frequency of exercise programs*
- *The percentage of staff who have completed/participated in exercises*
- *How the electrical corporation tracks who has completed the exercises*

An exemplar of the minimum acceptable level of information is provided in Table 8-51.

BVES does not currently conduct any internal exercises. BVES will revisit the desirability for internal exercises from time to time to determine whether such exercises are appropriate or beneficial.

External Exercises

The electrical corporation must report on its program(s) for conducting external discussion-based and operations-based exercises for service restoration due to wildfire. This must include, at a minimum, the types of discussion-based exercises (e.g., seminars, workshops, tabletop exercises, games) and operations-based exercises (e.g., drills, functional exercises, full-scale exercises), the schedule and frequency of external exercise programs, the percentage of public safety partners who have participated in these exercises and means for verification of external exercises.

An exemplar of the minimum acceptable level of information is provided in Table 8-51.

- *The types of discussion-based exercises (e.g., seminars, workshops, tabletop exercises, games) and operations-based exercises (e.g., drills, functional exercises, full-scale exercises)*
- *The schedule and frequency of exercise programs*
- *The percentage of public safety partners who have participated in these exercises*
- *How the electrical corporation tracks who has completed the exercises*

BVES conducts at least one tabletop and one functional simulation exercise annually. These exercises involve participating stakeholders from the Big Bear community and be coordinated with CPUC Cal Fire, Cal OES, communication providers, AFN representatives, and other public safety partners. Additionally, BVES coordinates with these stakeholders to develop and plan the exercises. The exercises seek to prepare BVES and its community partners for a PSPS and enhance their performance, communication protocols, notification practices, and restoration procedures and test the functionality of the plan to the extent practicable. BVES keeps detailed records of these plans and submits reports of these exercises to the CPUC as required. BVES also reviews the exercises to identify strengths and weaknesses of BVES actions, and seek to incorporate lessons learned, as appropriate.

Table 8-61 Internal Drill, Simulation, and Tabletop Exercise Program for Service Restoration

Category	Exercise Type	Purpose	Exercise Frequency	Position of Title of Personnel Required to Participate	Personnel Required	Personnel Completed	Form of Verification or Reference
	Tabletop	Wildfire and PSPS Preparation	Once per year	President	X	X	Exercise reported to the CPUC
				Utility manager	X	X	
				Field Operations Supervisor	X	X	
				Utility Engineer & Wildfire Supervisor	X	X	
				Customer Program Specialist	X	X	
				Accounting Supervisor	X	X	
				Logistic Group Leader	X	X	
				Others as required	X	X	
	Functional	Wildfire and PSPS	Once per year	President	X	X	Exercise reported to CPUC

		Preparation					
				Utility Manager	X	X	
				Field Operations Supervisor	X	X	
				Utility Engineer & Wildfire Supervisor	X	X	
				Customer Program Specialist	X	X	
				Accounting Supervisor	X	X	
				Logistic Group Leader	X	X	
				Others as required	X	X	

8.4.6 Customer Support in Wildfire and PSPS Emergencies

In this section of the WMP, the electrical corporation must provide an overview of its programs, systems, and protocols to support residential and non-residential customers in wildfire emergencies and PSPS events. The overview for each emergency service must be no more than one page. At a minimum, the overview must cover the following customer emergency services, per Public Utilities Code section 8386(c)(21):

- *Outage reporting*
- *Support for low-income customers*
- *Billing adjustments*
- *Deposit waivers*
- *Extended payment plans*
- *Suspension of disconnection and nonpayment fees*
- *Repair processing and timing*
- *List and description of community assistance locations and services*
- *Medical Baseline support services*

- *Access to electrical corporation representatives*

Reference the Utility Initiative Tracking ID where appropriate.

- Outage reporting – BVES notifies State and Local Agencies (Section 8.4.3.1), Public Policy Partners (Section 8.4.3.2), Mutual Aid Associations (Section 8.4.3.3), and Stakeholders (Section 8.4.4.1) as directed in the BVES EDRP and PSPS plans. BVES provides varied customer outreach programs including automated calls, text, social media, email alerts, radio and verbiage on its website.
- Support for low-income customers – BVES maintains a list of low-income customers that we will provide outreach to, as required based on the emergency situation. BVES provides a list of community assistance programs on its website and advertise them through its media outlets.
- Billing adjustments – BVES has in the past and will continue to provide bill adjustments as necessary depending on the emergency situation.
- Deposit waivers BVES has in the past and will continue to provide deposit waivers as necessary depending on the emergency situation.
- Extended payment plans BVES has in the past and will continue to provide extended payment plans as necessary depending on the emergency situation.
- Suspension of disconnection and nonpayment fees – BVES has in the past and will continue to provide suspension of disconnection and nonpayment fees as necessary depending on the emergency situation.
- Repair processing and timing – BVES notifies State and Local Agencies (Section 8.4.3.1), Public Policy Partners (Section 8.4.3.2), Mutual Aid Associations (Section 8.4.3.3), and Stakeholders (Section 8.4.4.1) of estimated repair processing and timing as outlined in the BVES EDRP and PSPS Plans. BVES provides this information through varied customer outreach programs including automated calls, text, social media, email alerts, radio and verbiage on its website.
- List and description of community assistance locations and services – BVES provides outreach to inform the customer base of community assistance that is available. BVES provides the information on its website, outreach to its CBO's, advertisements through social media, outreach to mobile home park managers, and bus stop ads.
- Medical Baseline support services – BVES updates the current list of medical baseline and AFN customers bi-monthly. This information is distributed internally and place the list on the PSPS portal for critical facilities to access if needed. BVES provides automated calls, texts, emails and door tags depending on the emergency situation.
- Access to electrical corporation representatives BVES representatives are available by phone on a 24-hour basis during an emergency. BVES provides updated emergency information to the local radio station and press to update emergency situation. Whenever possible, BVES management proactively provides management responses through the return of telephone calls or through local websites (e.g., Facebook) to keep customers informed of the emergency situation.

8.5 Community Outreach and Engagement

8.5.1 Overview

Community outreach, public awareness, and communications efforts are required to reduce the impact to customers and the community from an event causing interrupting of service and/or poses serious public risks. Effective planning and awareness also assist in limiting the scope of extreme events and avoiding escalation. BVES has altered how the company addressed the risk of catastrophic wildfires due to the increased presence of potential wildfire due to climate changes and environmental conditions. BVES works year-round to educate customers and the general public and works with community partners to improve outreach, awareness, and communications.

The Energy Resource Manager oversees communications plans and activities. Reporting to the energy Resource Manager is the Customer Service Supervisor, who manages communication activities. BVES's communication plan includes a two-pronged approach (1) proactive preparation before emergencies occur and (2) notifications during and after emergency events. Communications protocols vary slightly when dealing with stakeholders that include customers, first responders, the local mutual aid association, local government, among other key stakeholders.

The list below describes the goals and methods of informing each of these groups.

> Customer Outreach and Notifications: The goal of customer outreach is to educate and prepare customers for fire prevention, proactive de-energization, and other utility infrastructure-related emergencies. Communication formats are planned in English, Spanish, Tagalog, Vietnamese, Chinese, French, Mixteco and Zapoteco for online resources and when requested by customers. BVES is continuing to enhance its community outreach activities and has conducted a self-identified survey process to account for these populations. Indigenous communities surrounding the service area are investigated to account for the unique languages representing English as a Second Language (ESL) speakers. BVES collaborates with other community organizations to assure that a local community resource center is available to customers during emergencies. BVES aligns its communication with other organizations, so it is clear and consistent among the local and state organizations.

8.5.1.1 Objectives

In this section BVES summarizes the objectives for its 3-year and 10-year plans for implementing and improving its community outreach and engagement in Table 8-53, below.

Table 8-62 Community Outreach and Engagement Initiative Objectives (3-year plan)

Objectives for Three Years (2023-2025)	Applicable Initiative(s), Tracking ID(s)	Applicable Regulations, Codes, Standards, and Best Practices (See Notes)	Method of Verification (i.e., program)	Completion Date	Reference (Section and Page Number)

Continue to deploy and improve 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. Evaluate effectiveness of outreach efforts.	Public outreach and education awareness program, COE_1			31-Dec-25	
Continue to improve program to understand, evaluate, design, and implement wildfire and PSPS risk mitigation strategies, policies, and procedures specific to access and functional needs customers. Evaluate effectiveness of these efforts.	Engagement with access and functional needs populations, COE_2			31-Dec-25	

Work with stakeholders to develop and integrate 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. Evaluate effectiveness of these collaborative efforts.	Collaboration on local wildfire mitigation planning, COE_3			31-Dec-25	
Continue to be proactive in sharing and integration of best practices and collaborating with other electrical corporations on technical and programmatic aspects of WMP programs.	Best practice sharing with other utilities, COE_4			31-Dec-25	

Table 8-63 Community Outreach and Engagement Initiative Objectives (10-year plan)

Objectives for Ten Years (2026-2032)	Applicable Initiative(s), Tracking ID(s)	Applicable Regulations, Codes, Standards, and Best Practices (See Notes)	Method of Verification (i.e., program)	Completion Date	Reference (Section and Page Number)
Implement social media and other effective platforms to increase 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. Evaluate effectiveness of these outreach efforts.	Public outreach and education awareness program, COE_1				
Establish streamlined routine for sharing lessons learned and best practices among peers.	Best practice sharing with other utilities, COE_4				

8.5.1.2 Targets

Initiative targets are quantifiable measurements of activities identified in the WMP. Electrical corporations will show progress towards completing targets in subsequent reports, including QDRs and WMP Updates.

The electrical corporation must list all targets it will use to track progress on its grid design, operations, and maintenance for the next three years (2023–2025). Energy Safety's Compliance Assurance Division and third parties must be able to track and audit each target.37 For each initiative target, the electrical corporation must provide the following:

- *Utility Initiative Tracking IDs*
- *Projected targets for the three years of the Base WMP and relevant units*
- *Quarterly, rolling targets for end of 2023 and 2024 (inspections only)*
- *For 2023–2025, the "x% risk impact." The x% risk impact is the percentage risk reduction identified in Table 7-2 for a specific mitigation initiative (see Section 7.2.2.1 for calculation instructions)*
- *Method of verifying target completion*

The electrical corporation's targets must provide enough detail to effectively inform efforts to improve the performance (i.e., reduction in ignition probability or wildfire consequence) of the electrical corporation's community outreach and engagement initiatives.

Table 8-64 Community Outreach and Engagement Initiative Targets by Year

Initiative Activity	Tracking ID	Units	2023 Target	X% Risk Impact 2023	2024 Target	X% Risk Impact 2024	2025 Target	X% Risk Impact 2025	Method of Verification
Collaboration on local wildfire mitigation planning	COE_3	Develop Program	100 %		Review and Maintain Program		Review and Maintain Program		Version History
Best practice sharing with other utilities	COE_4	Work Groups, Conferences	15		15		15		Quantitative

Table 8-65 PSPS Outreach and Engagement Initiative Targets by Year

Initiative	Tracking ID	Units	Target End	Target End	End of Ye	X% Risk Imp	Target End	Target End	End of Ye	X% Risk Imp	Target	X% Risk Imp	Method of

Activity			**of Q2 2023**	**of Q3 2023**	**ar Target 2023**	**act 2023**	**of Q2 2024**	**of Q3 2024**	**ar Target 2024**	**act 2024**	**2025**	**act 2025**	**Verification**
Public outreach and education awareness program	COE_1	Number of Public Outreach and Education Events	180	270	360		180	270	360		360		Quantitative
Engagement with access and functional needs populations	COE_2	AFN customer needs verifications	6	9	12		6	9	12		12		Quantitative

8.5.1.3 Performance Metrics Identified by BVES

Performance metrics indicate the extent to BVES lists the performance metrics used to evaluate the effectiveness of its community outreach and engagement in reducing wildfire and PSPS risk. For each of the performance metrics listed, BVES reports its performance since 2020, projected performance for 2023-2025, and the method of verification.

Table 8-66 Community Outreach and Engagement Performance Metrics Results by Year

Performance Metrics	**2020**	**2021**	**2022**	**2023 Projected**	**2024 Projected**	**2025 Projected**	**Method of Verification (e.g., third-party verification, WMP)**
Public outreach and education events				360	360	360	Third-party QDR verification

AFN customer verifications				12	12	12	Third-party QDR verification

8.5.2 Public Outreach and Education Awareness Program

In this section BVES provides a high-level overview of its public outreach and education awareness program(s) for wildfires; outages due to wildfires, PSPS, and protective equipment and device settings; service restoration before, during, and after the incidents (as required by Public Utilities Code section 8386(c)(19)(B)); and vegetation management.

BVES believes it is of best practice to keep its customers informed on BVES regular operations and planned actions during the fire season to reduce risk.

Community outreach, public awareness, and communications efforts are required to reduce the impact to customers and the community from an event causing interrupting of service and/or poses serious public risks. Effective planning and awareness also assist to limit the scope of extreme events and avoid escalation. BVES has altered how the company addressed the risk of catastrophic wildfires due to the increased presence of potential wildfire due to climate changes and environmental conditions. BVES works year-round to educate customers and the general public and works with community partners to improve outreach, awareness, and communications.

The Energy Resource Manager oversees communications plans and activities. Reporting to the energy Resource Manager is the Customer Service Supervisor, who manages communication activities. BVES's communication plan includes a two-pronged approach (1) proactive preparation before emergencies occur and (2) notifications during and after emergency events. Communications protocols vary slightly when dealing with stakeholders that include customers, first responders, the local mutual aid association, local government, among other key stakeholders. The goal of customer outreach is to educate and prepare customers for fire prevention, proactive de-energization, and other utility infrastructure-related emergencies. Communication formats are planned in English, Spanish, Tagalog, Vietnamese, Chinese, French, Mixteco and Zapoteco for online resources and when requested by customers. BVES is continuing to enhance its community outreach activities and has conducted a self-identified survey process to account for these populations. Indigenous communities surrounding the service area are investigated to account for the unique languages representing English as a Second Language (ESL) speakers. BVES collaborates with other community organizations to assure that a local community resource center is available to customers during emergencies. BVES aligns its communication with other organizations, so it is clear and consistent among the local and state organizations.

Table 8-67 List of Target Community Groups

Target Community Group	Interests or Concerns Before, During, and After Wildfire and PSPS Events

AFN/Medical Baseline	AFN customers are unable to use power for devices/equipment for health, safety, and independence during a PSPS event

- *Community partners the electrical corporation is working with or intends to work with to support its community outreach and education programs. Partnerships are important to the success of public education and awareness efforts. Good strategies grow from collaboration, and cooperation is essential for developing consistent, harmonized, and standardized messages that will be scaled up and repeated frequently enough to become common knowledge. An exemplar of the minimum acceptable level of information is provided in Table 8-58.*

Table 8-68 List of Target Community Partners

Community Partners	County	City
N/A		

- *Description of the various outreach and education awareness programs (i.e., campaigns, informal education, grant programs, participatory learning) that the electrical corporation implements before, during, and after wildfire, vegetation management, and PSPS events. Successful programs may use many approaches, settings, and tools to repeat their messages for maximum impact. In addition, the electrical corporation must describe how it implements its overall program, including staff and volunteer needs, other resource needs, method for implementation (e.g., industry best practice, latest research in methods for risk communication, social marketing), long-term monitoring and evaluation of each program's success, need for improvement, etc. The narrative for this section is limited to two to three pages. The electrical corporation must also provide the requested information in tabulated format. An exemplar of the minimum acceptable level of information is provided in Table 8-59.*

Table 8-69 Community Outreach and Education Programs

Core Activity	Event Type	Period of Application (Before, During, After Incident)	Name of Outreach or Education Program	Description of Program	Target Audience	Reference/Link
Website Information	Wildfire	Before	General Wildfire Safety			
Website Information	PSPS	Before	Public Safety Power Shutoff			
Website Information	Wildfire	Before				
Website Information	Vegetation Management	Before				

Website Information	Wildfire & PSPS	Before				
Safety Webinars	Wildfire	Before				

8.5.3 Engagement with Access and Functional Needs Populations

BVES is a small electric utility in the Big Bear Lake recreational area of the San Bernardino Mountains located about 80 miles east of Los Angeles that provides electric distribution service to 22,430 residential customers in a resort community with a mix of approximately 40% full-time and 60% part-time residents. Its service area also includes 1,519 commercial, industrial and public-authority customers, including two ski resorts and the local waste-water treatment facility. BVES differs significantly from California's largest electric investor-owned utilities, Pacific Gas & Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company (collectively, the "Large IOUs"). BVES has a substantially smaller customer base over which to spread fixed costs of service, has a mountainous and remote service territory subject to greater seasonal climate fluctuations, and faces greater resource limitations in comparison to the Large IOUs. The Commission has historically recognized these distinctions between BVES and the Large IOUs. BVES continues work on system modifications to CIS and OMS to allow the recording of AFN customer categories and data beyond medical baseline customers. As of (DATE), the CIS system identifies (#) Medical Base Line (MBL) customers marked as AFN customers.

BVES is continuously working to evaluate and seeks to implement system enhancements, modifications, and manual work around on the CIS, OMS, and GIS systems. Data tracking continues to be reviewed for areas of improvement to allow BVES more visibility into the AFN customer population. As a part of BVES' recent and ongoing system improvements, the capability to map AFN customers beyond MBL is anticipated to be integrated into the OMS system and further refined throughout 2023.

8.5.4 Collaboration on Local Wildfire Mitigation Planning

In this section, BVES provides a high-level overview of its plans, programs, and/or policies for collaborating with communities on local wildfire mitigation planning within its service territory in Table 8-61, below. BVES current gaps and limitations in its collaboration efforts with local partners on local wildfire planning efforts are listed in Table 8-62.

Table 8-70 Collaboration in Local Wildfire Mitigation Planning

Name of County, City, or Tribal Agency or Civil Society Group (e.g., nongovernment organization, fire safe council)	Program, Plan, or Document	Last Version of Collaboration	Level of Collaboration
Local County Resource Management Agency	Local County General Plan, Safety Element, Wildfires	2022 version (06/2021)	Attended a virtual meeting on 02/02/2022 at 1 pm PDT

			Provided verbal comments and input
Local Fire Safe Council	Structural hardening grant program	2021/2022	Financier
Local County Resource Conservation District	Chipper program	Planned for 12/2023	Financier
Local Tribal Agency	Tribal Government Wildfire Safety Plan	2022 version (06/2021)	Attended a virtual meeting on 02/02/2022 at 1 pm PDT Provided verbal comments and input

- *In a separate table, the electrical corporation must provide a list of current gaps and limitations in its collaboration efforts with local partners on local wildfire planning efforts. Where gaps or limitations exist, the electrical corporation must indicate proposed means and methods to increase collaborative efforts.*

An exemplar of the minimum acceptable level of information is provided in Table 8-61.

Table 8-71 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
Low collaboration requests	Less than 5% of local government and civil society stakeholder groups seek collaboration activities.	**Strategy** – Create web content notifying the public, local government, and civil society organizations of the electrical corporation's resources to provide support on local wildfire mitigation planning efforts. Assign a local wildfire planning liaison to be available, as needed, for local planning efforts. **Target timeline** – Develop and post web content by May 2023 and hire two local wildfire planning liaisons by March 2023.

8.5.5 Best Practice Sharing with Other Electrical Corporations

In this section BVES provides a high-level overview of its policy for sharing best practices and collaborating with other electrical corporations on technical and programmatic aspects of its WMP program.

Table 8-72 Best Practice Sharing with Other Electrical Corporations

Best Practice Subject	Dates of Collaboration (YYYY-YYYY)	Technical or Programmatic	Utility Partner(s)	Description of Best Practice Sharing or Collaborating	Outcome
Covered conductor effectiveness	2020-Current	Technical	PGE, SCE, SDGE, Liberty, PC, BVES	The IOUs commissioned a joint study to assess the effectiveness and reliability of covered conductors (CCs) for overhead distribution system hardening. The aim is to develop consistent criteria and measurements for evaluating effectiveness of CCs. Refer to the report entitled "Effectiveness of Covered Conductors: Failure Mode Identification and Literature Review," dated December 22, 2021, for more details.	Ongoing • CCs are a mature technology (in use since the 1970s) and have the potential to mitigate several safety, reliability, and wildfire risks inherent to bare • conductors. This is due to the reduced vulnerability to arcing/faults afforded by the multi-layered polymeric insulating sheath material. • Of the 10 hazards that affect bare conductors, CCs have the potential to mitigate six (tree/vegetation contact, wind-induced contact, third-party damage, animal-related damage, public/worker impact, and moisture).

					• Laboratory studies and field experience have shown that CCs largely mitigated arcing due to external contact. • Several CC-specific failure modes exist that require operators to consider additional personnel training, augmented installation practices, and adoption of new mitigation strategies (e.g., additional lightning arrestors, conductor washing programs).
Vegetation Manageme nt Best Practice Sharing					
Risk Model Working Group					

9. Public Safety Power Shutoff

9.1 Overview

In Sections 9.1–9.5 the electrical corporation:

- *Provides a high-level overview of key PSPS statistics*
- *Identify circuits that have been frequently de-energized and provide measures for how the electrical corporation will reduce the need for, and impact of, future PSPS of those circuits*
- *Describe expectations for how the electrical corporation's PSPS program will evolve over the next 3 and 10 years*
- *Describe any lessons learned for PSPS events occurring since the electrical corporation's last WMP submission*
- *Describe the electrical corporation's protocols, processes, and procedures for PSPS implementation*

9.1.1 9Key PSPS Statistics

In this section, the electrical corporation must include a summary table of PSPS event data. These data must be calculated from the same source used in the GIS data submission (i.e., they should be internally consistent). If it is not possible to provide these data from the same source, the electrical corporation must explain why. Table 9-1 provides an example of the minimum acceptable level of information for a summary of PSPS event data.

In this section, BVES provides summary table of PSPS event data. The data is calculated from the same source used in the GIS data submission.

Table 9-1 PSPS Statistics

Year	# of Events	Circuits De-energized	Customers Impacted	Customer Minutes of Interruption
Jan 1 – Dec 31, 2020	0	N/A	N/A	N/A
Jan 1 – Dec 31, 2021	0	N/A	N/A	N/A
Jan 1 – Dec 31, 2022	0	N/A	N/A	N/A

BVES 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. 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. As BVES continues to reduce ignition risk, BVES anticipates the likelihood to need to use its PSPS to become even more remote, but BVES will continue to evaluate the risk and necessity for its use. Finally, BVES incorporates lessons learned across California regarding the use of PSPS and will update as necessary its PSPS Plan and Emergency Disaster and Response Plan (EDRP) accordingly.

No direct lessons learned from BVES-initiated activations can be applied to this WMP Update as BVES has not met thresholds to initiate a PSPS event. The triggering threshold has also not changed based on the implementation of WMP initiatives. In the future, BVES anticipates continued re-designation of high-risk areas to reduce risk designations after years of significant WMP initiative implementation as mitigations are deployed and real-time modeling capabilities are enhanced. BVES will also re-evaluate its PSPS trigger thresholds.

The circuits currently identified for de-energization and customer impact include North Shore Circuit (1,021 customers), Boulder Circuit (1,063 customers), Lagonita Circuit (946 customers), Clubview Circuit (740 customers), Goldmine Circuit (950 customers), and Erwin Lake Circuit (197 customers). If the Radford Circuit is de-energized, the load will be shifted to the Shay Line and no direct customers will be impacted.

9.1.2 Identification of Frequently De-energized Circuits

Public Utilities Code section 8386(c)(8) requires the "[i]dentification of circuits that have frequently been de-energized pursuant to a PSPS event to mitigate the risk from wildfire and the measures taken, or planned to be taken, by the electrical corporation to reduce the need for, and impact of, future PSPS of those circuits, including, but not limited to, the estimated annual decline in circuit PSPS and PSPS impact on customers, and replacing, hardening, or undergrounding any portion of the circuit or of upstream transmission or distribution lines." To comply, the electrical corporation is required to populate Table 9-2 and provide a map showing the frequently de-energized circuits.

The map must show the following:

- *All circuits listed in Table 9-2, colored or weighted by frequency of PSPS*
- *HFTD Tiers 2 and 3 contour overlay*

Public Utilities Code section 8386(c)(8) requires the "Identification of circuits that have frequently been de-energized pursuant to a PSPS event to mitigate the risk of wildfire and the measures taken, or planned to be taken, by BVES to reduce the need for, and impact of, future PSPS of those circuits, including, but not limited to, the estimated annual decline in circuit PSPS and PSPS impact on customers, and replacing, hardening, or undergrounding any portion of the circuit or of upstream transmission or distribution lines.

Table 9-2 De-energized Circuits

Entry #	Circuit ID	Name of Circuit	Dates of Outages	# of Customers Served by Circuit	# of Customers Affected	Measures Taken, or Planned to be Taken, to Reduce the Need for and Impact of Future PSPS of Circuit
N/A	N/A	N/A	N/A	N/A	N/A	N/A

BVES has not activated any PSPS events thus cannot provide a listing of frequently de-energized circuits. The utility has prioritized high-risk circuits for mitigation over the next ten years and does not anticipate the need to utilize any proactive de-energizations. However, BVES has identified circuits for de-energization if PSPS triggers are met and maintains complete PSPS Protocols and conducts PSPS exercises to be prepared in case BVES must initiate a PSPS event.

These circuits for potential PSPS events are identified in the figure below.

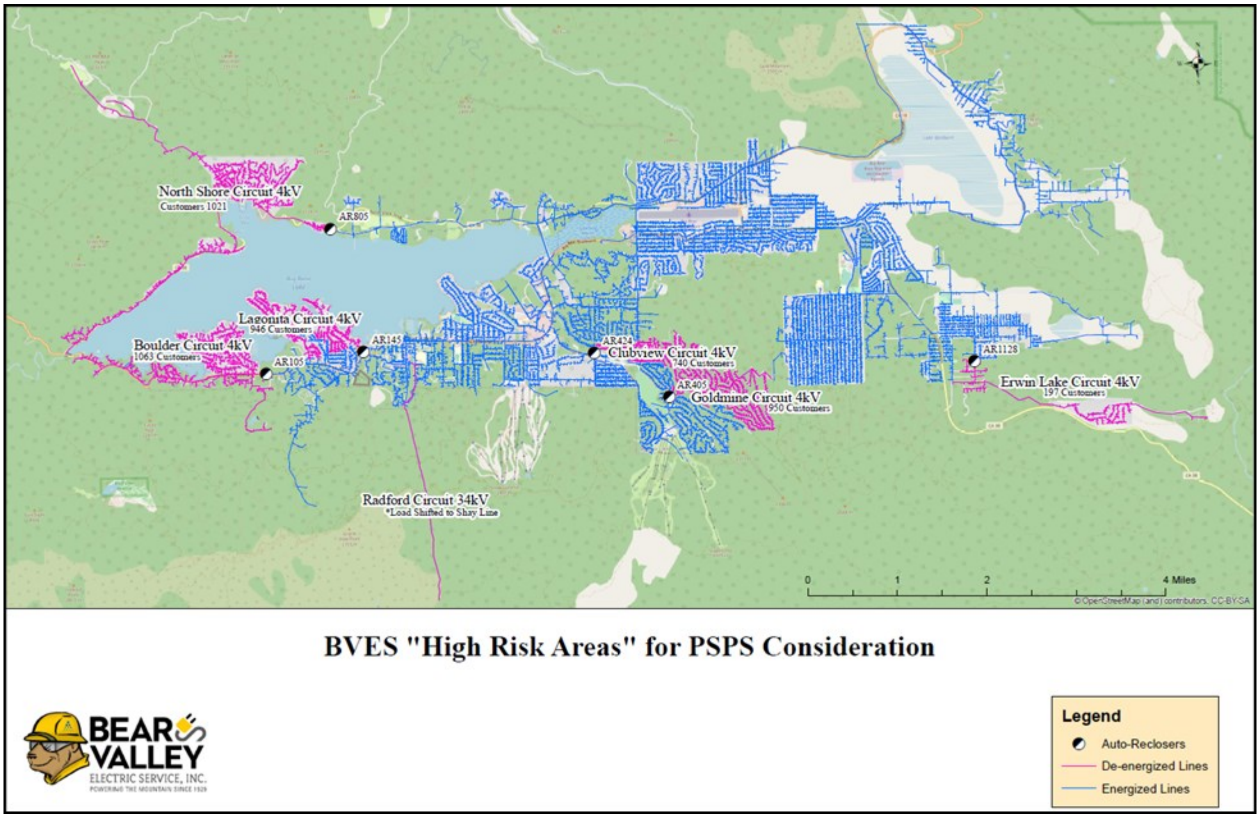


Figure 9-1 BVES High Risk Areas for PSPS Consideration

9.1.3 Objectives

Each electrical corporation must summarize the objectives for its 3-year and 10-year plans to reduce the scale, scope, and frequency of PSPS events. These summaries must include the following:

- *Identification of which initiative(s) in the WMP the electrical corporation is implementing to achieve the stated objective, including Utility Initiative Tracking IDs*
- *Reference(s) to applicable codes, standards, and best practices/guidelines and an indication of whether the electrical corporation exceeds an applicable code, standard, or regulation*
- *Method of verifying achievement of each objective*
- *A completion date for when the electrical corporation will achieve the objective*
- *Reference(s) to the WMP section(s) or appendix, including page numbers, where the details of the objective(s) are documented and substantiated*

In this section, BVES summarizes the objectives for its 3-year and 10-year plans to reduce the scale, scope, and frequency of PSPS events. The summaries include the following:

- Identification of which initiative(s) in the WMP the electrical corporation is implementing to achieve the stated objective, including Utility Initiative Tracking IDs
- Reference(s) to applicable codes, standards, and best practices/guidelines and an indication of whether the electrical corporation exceeds an applicable code, standard, or regulation
- Method of verifying achievement of each objective
- A completion date for when the electrical corporation will achieve the objective
- Reference(s) to the WMP section(s) or appendix, including page numbers, where the details of the objective(s) are documented and substantiated

Table 9-3 PSPS Objective (3-year plan)

Table 9-4 PSPS Objective (3-year plan)

Objectives for Three Years (2023-2025)	**Applicable Initiative(s) & Tracking ID(s)**	**Applicable Regulations, Codes, Standards, and Best Practices (see note)**	**Method of Verification**	**Completion Date**	**Reference (section & page #)**
Automate PSPS notifications to customers	Public emergency communication strategy EP-3 Public outreach and education awareness program COE-1	CPUC's PSPS guidelines and rules	Contract with communications firm to automate notifications; demonstration of automated process; post-event reports	September 2023	Section 8.4.4
Conduct tabletop and functional exercise each years prior to the fire season.	Emergency preparedness plan EP-1 External collaboration and coordination EP-2 Public emergency communication strategy Preparedness and planning for service restoration EP-4	CPUC's PSPS guidelines and rules	Tabletop exercise results and Pre and Post Season Report		Section 8.4.2

	Customer support in wildfire and PSPS emergencies EP-5				
Conduct service restoration training with supervisory and field personnel each year prior to the fire season.	Emergency preparedness plan EP-1 External collaboration and coordination EP-2 Public emergency communication strategy Preparedness and planning for service restoration EP-4 Customer support in wildfire and PSPS emergencies EP-5	CPUC's PSPS guidelines and rules	Training Log		Section 8.4.2
Conduct community and stakeholder PSPS briefings each year prior to the fire season.	Public emergency communication strategy EP-3	CPUC's PSPS guidelines and rules	Annual Community Briefing Report Outreach Records		Section 8.4.4

Continue to conduct comprehensive outreach to identify households with AFN persons.	Public emergency communication strategy EP-3 Engagement with access and functional needs populations COE-2	CPUC's PSPS guidelines and rules	Contract with communications firm to automate notifications; demonstration of automated process; post-event reports		Section 8.4.4

Note: An asterisk indicates that the electrical corporation exceeds a particular code, regulation, standard, or best practice. The electrical corporation must provide a reference to the appendix section and page providing further documentation, justification, and substantiation.

Table 9-5 PSPS Objective (10-year plan)

Objectives for Ten Years (2026-2032)	Applicable Initiative(s) & Tracking ID(s)	Applicable Regulations, Codes, Standards, and Best Practices (see note)	Method of Verification	Completion Date	Reference (section & page #)
Evaluate and adjust as appropriate PSPS activation thresholds as grid hardening initiatives are completed and the risk of ignitions is reduced.	Emergency preparedness plan EP-1	CPUC's PSPS guidelines and rules	N/A		Section 8.4.2
Reassess high risk areas and sectionalizing switches as grid hardening initiatives are completed and the risk of ignitions is reduced in the high-risk areas. (For example, as a high-risk area is shrunk due to grid hardening efforts, new sectionalizing devices may be	Emergency preparedness plan EP-1	CPUC's PSPS guidelines and rules	N/A		Section 8.4.2

needed to be able isolation only the smaller high risk area.)					
As social media and communications technology continue to evolve, evaluate how to adapt PSPS communications plan to improve and streamline communications with stakeholders and customers.	Public emergency communication strategy EP-2		Contract with communications firm to automate notifications; demonstration of automated process; post-event reports Internal records of outreach		Section 8.4.4

Note: An asterisk indicates that the electrical corporation exceeds a particular code, regulation, standard, or best practice. The electrical corporation must provide a reference to the appendix section and page providing further documentation, justification, and substantiation.

9.1.4 Targets

Initiative targets are forward-looking quantifiable measurements of activities identified by each electrical corporation in its WMP. Electrical corporations will show progress toward completing targets in subsequent reports, including QDRs and WMP Updates.

The electrical corporation must list all targets it uses to track progress on reducing the scope, scale, and frequency of PSPS for the three years of the Base WMP. Energy Safety's Compliance Assurance Division and third parties must be able to track and audit each target.48 For each initiative target, the electrical corporation must provide the following:

- *Utility Initiative Tracking IDs.*
- *Projected targets for the three years of the Base WMP and relevant units.*
- *The expected "x% risk impact" for each of the three years of the Base WMP. The expected x% risk impact is the expected percentage risk reduction per year, as described in Section 7.2.2.2.*
- *Method of verifying target completion.*

The electrical corporation's targets must provide enough detail to effectively inform efforts to improve the performance of the electrical corporation's initiatives aimed at reducing the scope, scale, and frequency of its PSPS events.

Table 9-6 PSPS Targets

Initiative Activity	Tracking ID	2023 Target & Unit	x% Risk Impact 2023	2024 Target & Unit	x% Risk Impact 2024	2025 Target & Unit	x% Risk Impact 2025	Method of Verification
Emergency preparedness plan	EP_1	N/A	N/A	N/A	N/A	N/A	N/A	N/A
External collaboration and coordination	EP_2	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Public emergency communication strategy	EP_3	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Preparedness and planning for service restoration	EP_4	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Customer support in wildfire and PSPS emergencies	EP-5	N/A	N/A	N/A	N/A	N/A	N/A	N/A

Due to the nature of BVES having not experienced a PSPS event the initiatives related to PSPS are in place to verify readiness in the case of an event. These initiatives are not designed to reduce risk as there has been no risk to reduce. Actions are taken on these initiatives on a quarterly basis and updates and adjustments are made on an as needed basis. BVES's PSPS Exercises also help to determine the effectiveness of the initiatives and guide future updates.

9.1.5 Performance Metrics Identified by the Electrical Corporation

Performance metrics indicate the extent to which an electrical corporation's Wildfire Mitigation Plan is driving performance outcomes. Each electrical corporation must:

- *List the performance metrics the electrical corporation uses to evaluate the effectiveness of reducing reliance on PSPS*

For each of these performance metrics listed, the electrical corporation must:

- *Report the electrical corporation's performance since 2020 (if previously collected)*
- *Project performance for 2023-2025*
- *List method of verification*

The electrical corporation must ensure that each metric's name and values are the same in its WMP reporting as its QDR reporting (specifically, QDR Table 2 and QDR Table 3). Metrics listed in this section that are the same as performance metrics required by Energy Safety and reported in QDR Table 2 (Performance Metrics)50 must match those reported in QDR Table 2. Metrics listed in this section that are not the same as any of the performance metrics identified by Energy Safety and reported in QDR Table 2 must match those reported in QDR Table 3.

The electrical corporation must:

- *Summarize its self-identified performance metric(s) in tabular form*
- *Provide a brief narrative that explains trends in the metrics*

Table 9-6 provides an example of the minimum acceptable level of information.

In addition to the table, the electrical corporation must provide a narrative (two pages maximum) explaining its method for determining its projected performance on these metrics (e.g., PSPS consequence modeling, retrospective analysis).

PSPS Evolution Timeline

In 2022, BVES contracted with Technosylva to provide real-time situational awareness through on-demand fire spread predictions and impact analysis, wildfire risk forecasting for customer assets and the service area using daily weather prediction integration and asset risk analysis using historical weather climatology. BVES plans to use this to analyze whether PSPS activation should occur, or at least add granularity to the PSPS threshold, in the future. Additional quantitative analysis of this projected evolution will be available over the year with full deployment in 2023.

In 2022, BVES updated its current PSPS Plan and Protocols to align with Phase 3 de-energization guidelines issued under D. 21-06-034. In addition to this effort, BVES revised its PSPS Plan and Protocol to be more action-oriented and concise to promote its effectiveness during an implementation.

While BVES does not anticipate an increase in PSPS activation, pre- and post-season activities for PSPS awareness have been made more robust through quarterly engagements with members of the public safety partner network. BVES held a tabletop simulation on April 15, 2022, enabling a run-through process of protocol activation with emergency and fire response personnel. On June 21, 2022, BVES conducted a PSPS functional exercise which included a community awareness workshop to address pre-season concerns, review its protocols, and forecast for proactive de-energization. BVES filed its annual Pre-Season Report on July 1, 2022 with the CPUC.

BVES also conducted public outreach and published its vision for necessity of PSPS on its website. Due to previous, ongoing, and future grid hardening efforts, the projected risk outlook relative to system hardening efforts carried out on prioritized circuits indicates a lower risk forecast as these initiatives are executed over ten years. This reduces the likelihood and need to initiate PSPS events.

BVES has not initiated any PSPS events over the past three years and does not forecast an imminent need to de-energize in the future based on a one, three, or ten-year forecast. The two tables 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 6 years. The data indicates that the threshold for BVES to direct a PSPS event was not experienced in the BVES service area.

Table 9-7 Highest Daily Wind Gust and Sustained Wind on High-Risk Days

Highest Daily Wind Gust on High-Risk Days							
Wind Gusts	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**
>55	0	0	0	0	0	0	0
50 to 54	0	0	0	0	0	0	0
40 to 49	0	0	0	1	1	2	1
30 to 39	7	5	6	1	5	5	3
20 to 29	78	39	64	27	65	51	56
<20	66	74	59	58	90	27	31
Highest Daily Sustained Wind on High-Risk Days							
Wind Gusts, Sustained	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**
>55	0	0	0	0	0	0	0
50 to 54	0	0	0	0	0	0	0
40 to 49	0	0	0	0	0	0	0
30 to 39	0	0	0	0	0	1	0
20 to 29	2	6	5	3	7	4	4
<20	149	112	124	84	154	83	87

Table 9-8 National Fire Danger Rating System (NFDRS) Historic Data

NFRDS	2016	2017	2018*	2019*	2020	2021	2022
G-Low Risk	71	109	26	189	108	87	40
Y-Moderate Risk	144	138	169	66	97	187	232
B-High Risk	138	103	122	78	152	90	91
O-High Risk	9	15	7	9	6	0	0

R-High Risk	4	0	0	0	3	0	0

*NFDRS not available for some days due to Federal Government shutdown.

Because BVES has not had to initiate PSPS events, it is not quantifiable to reduce the frequency, scope, or duration of future PSPS events. However, BVES does not view lack of PSPS events as a case for complacency. Accordingly, BVES incorporates PSPS lessons learned from BVES's observation and review of PSPS actions taken by other utilities in California.

In addition to its own plan for proactive de-energization, BVES may also be impacted by PSPS events triggered by SCE, because SCE's system supplies the majority of electric power to BVES's system. Accordingly, BVES closely monitors and coordinates with developments at SCE and is ready to respond to any SCE PSPS that may cut imports to BVES. Thus far, SCE has not enacted a PSPS on a power supply line to BVES.

Because BVES has never enacted a PSPS and believes there is a low likelihood BVES will need to enact a PSPS in the future, BVES does not have a defined vision for the continued evolution of its PSPS Plan. However, BVES recognizes climate change is changing historical weather patterns and fire conditions including severity and length of the fire season. In future WMP updates, BVES will continue to assess the historical record of fire weather conditions to determine any instances where a PSPS activation would have been justified using BVES's PSPS thresholds to assist in scenario development of forecasted risk. Taking no action to harden circuits or reduce the impact of PSPS events, would leave BVES's customers and stakeholders vulnerable to future extreme fire weather events that could necessitate PSPS. Therefore, over the course of the ten-year planning period, grid hardening initiatives, enhanced vegetation management programs, more robust forecasting capabilities, and increased situational awareness will continue to keep the likelihood of PSPS activation remote despite changing climate and forest conditions in the BVES service territory. Additionally, BVES will continue to coordinate with public safety partners and community members and distribute PSPS Plan and wildfire safety updates ahead of each wildfire season.

The data provided in Table 9-9 is a summary based on the most current information available at the time and is subject to modification resulting from additional analyses, internal outage audits and assessments, completed following submission of this 2023 WMP Update.

Scope, scale, and frequency of PSPS activations will be mitigated through BVES's seasonal operational posture that directs the following actions taken throughout the year:

1. The Radford Line is de-energized from April to October or as otherwise recommended by the Field Operations Supervisor. Re-energization can be achieved should the forecasted demand require additional generation, for planned maintenance, system upgrades, or other-directed action. No redundancy degradation exists with this operational protocol since the supply lines from the Lucerne area are separate and independent of one another. The Radford Line assists to supply power during winter high load periods as BVES profiles as a winter-peaking utility.

2. From April to October, BVES will place certain auto-reclosers, fuse TripSavers, and switches in "manual" operation such that they will not shut and test upon detection of a fault. A specific list of switched mechanisms will be derived ahead of each fire season to ensure load forecasts align with present conditions to the best ability

possible. The completion of the Grid Automation Project, which establishes connectivity and control of these devices, will necessitate a policy revision or re-evaluation.

a. When an auto-recloser, switch, or fuse-replacing TripSaver placed in “Manual” due to the above policy trips opens, 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 “Green” or “Yellow,” 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.

3. Due to reduced load in non-winter period, the Utility Engineer & Wildfire Mitigation Supervisor developed specific fast trip, three-shot settings for auto-reclosers and other protective devices in the field to enhance fire prevention. The list of affected devices will be provided to the Utility Manager and the Field Operations Supervisor. Additionally, the Field Operations Supervisor will provide the settings that the Field Operations staff will be required to set on each device. Specific dates to enter these reduced settings will be recommended by the Field Operations Supervisor and approved by the Utility Manager. Engineering staff will not change device settings without the Field Operations Supervisor’s authorization.

It should be noted that while BVES is able to evaluate its facilities and determine the limiting wind speeds when distribution facilities are possibly at high risk, 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. Isolating areas with switching devices allow for sectionalization of the areas affected, which will be communicated to affected parties if a decision to activate PSPS is made.

Table 9-9 Projected PSPS Performance

Performance Metrics	**2020**	**2021**	**2022**	**2023 Projected**	**2024 Projected**	**2025 Projected**	**Method of Verification (e.g., third-party evaluation, QDR)**
PSPS Notification	0	0	0	0	0	0	QDR
Circuits De-energized	0	0	0	0	0	0	QDR
Customers impacted	N/A	N/A	N/A	0	0	0	QDR

9.2 Protocols on PSPS

The electrical corporation must describe its protocols on PSPS implementation including:

- *Risk thresholds (e.g., wind speed, FPI, etc.) and decision-making process that determine the need for a PSPS. Where the electrical corporation provides this information in another section of the WMP, it must provide a cross-reference here rather than duplicating responses.*

- *Method used to compare and evaluate the relative consequences of PSPS and wildfires.*

- *Outline of the strategic decision-making process for initiating a PSPS (e.g., a decision tree). Where the electrical corporation provides this information in another section of the WMP, it must provide a cross-reference here rather than duplicating responses.*

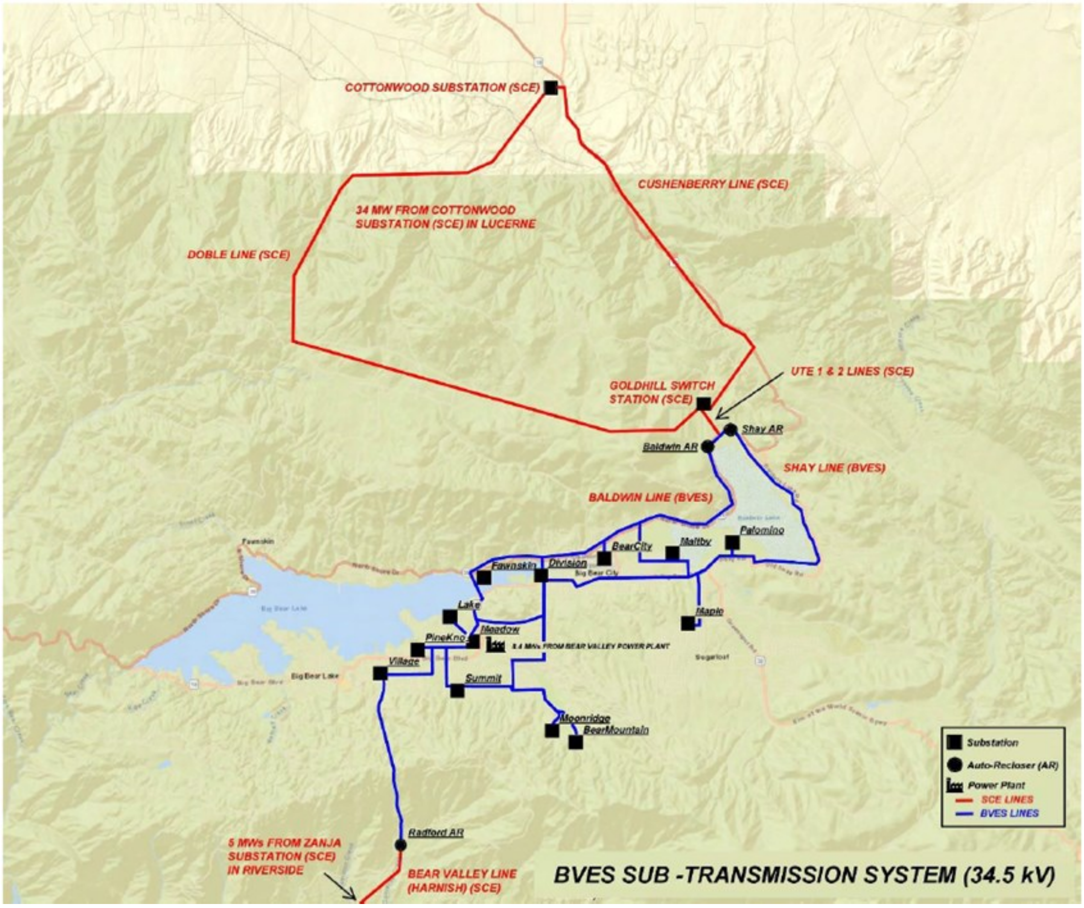
- *Protocols for mitigating the public safety impacts of PSPS, including impacts on first responders, health care facilities, operators of telecommunications infrastructure, and water electrical corporations/agencies.*

The protocols on PSPS, including the following elements, are described in detail in the attached PSPS Plan. BVES updated its existing PSPS Plan to align with D. 21-06-034 Phase 3 guidelines. BVES also made additional revisions to make the PSPS Plan more actionable, focused, and concise.

While BVES does not have a formal quantitative method to evaluate the potential consequence of PSPS and wildfires, lessons learned can be drawn from similar utilities across the state. BVES has not experienced a wildfire event or a PSPS activation to capture challenging and successful takeaways. Once BVES fully implements Technosylva's services, BVES will be able to have a near real-time ability to quantify the consequence of wildfires, and, therefore, the ability to evaluate and compare the wildfire consequence and risk to the consequences of a PSPS event.

Currently, the highest probability for triggering a PSPS event within the BVES service territory is the loss of SCE's energy imports to the BVES service area due to a SCE-directed PSPS of the SCE supply lines. BVES imports from SCE are subject to PSPS activation initiated by SCE. SCE may activate a proactive de-energization of these lines even if these circuits within the BVES service area and conditions do not meet BVES PSPS thresholds. To address the possibility of SCE-directed PSPS events, BVES proposes to construct an energy storage project of approximately 5 MW/20 MWh (four-hour) lithium-ion utility-grade battery serving the BVES service area. In conjunction with the existing Bear Valley Power Plant and potential utility scale solar, BVES would be able to initially meet its energy demands during a supply drop from SCE for several hours depending on load shedding strategy. BVES will continue with project planning and evaluation of an energy storage and solar facility within the BVES service territory, though, this project timeline has been extended due to siting delays.

Figure 9-2 BVES Supply Lines, Sources of Power and Sub-Transmission System



The table below outlines BVES's action plan for addressing partial or complete loss of power due to SCE supply line de-energization events.

Table 9-10 BVES Action for SCE Lines De-Energized due to PSPS

Condition	BVES Action
SCE De-energizes Doble or Cushenberry Line for PSPS.	Notify key internal staff and brief Field Operations staff on condition for situational awareness. Energize Radford Line as needed to meet load demand. If the Utility Manager deems it necessary, energize the Radford Line as needed for reliability. Startup BVPP as needed to meet load demand. No reduction on load necessary, since the Doble and Cushenberry are capable of carrying the other's load. Implement applicable portions of BVES Emergency Response Plan for a partial loss of SCE supply lines
SCE De-energizes Bear Valley Line for PSPS.	Notify key internal staff and brief Field Operations on conditions for situational awareness.

	If Radford is energized, shift loads to Shay Line prior to deenergizing for PSPS. Generally, this should be done about 4 hours prior to the SCE de-energizing the line. If needed, start up BVPP to meet load demand. If needed, instruct interruptible customers (Bear Mountain Resorts) to reduce load as needed to meet load demand. Implement applicable portions of BVES EDRP for a partial loss of SCE supply lines
SCE De-energizes Doble or Cushenberry and Bear Valley Lines for PSPS.	Notify key internal staff and brief Field Operations on conditions for situational awareness. 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. Prepare for potentially losing all SCE supply lines into BVES service area. Prepare for sustained BVPP operations and rolling blackouts. Evaluate distribution circuit loads. Implement applicable portions of BVES Emergency Response Plan for a partial loss of SCE supply lines.
SCE De-energizes Doble and Cushenberry Lines for PSPS.	Notify key internal staff and brief Field Operations on condition for situational awareness. If not already done, energize the Radford Line. Four hours prior to SCE de-energizing the lines, per the Field Operations Supervisor's direction, shift as much of the load to BVPP and Radford Line as follows: Open the Shay and Baldwin automatic reclosers. "Express" the Radford Line to Meadow Substation without overloading the Radford Line per Field Operations' switching order. Startup BVPP, place enginators on-line and increase load to within the combined capacity of the BVPP and Radford Line. Implement BVES Emergency Response Plan for sustained loss of SCE supplies from Lucerne including "rolling blackout" procedures. Prepare for sustained BVPP operations and rolling blackouts. Frequently monitor distribution circuit loads.
SCE de-energizes Doble, Cushenberry, and Bear Valley Lines for PSPS.	Notify key internal staff and brief Field Operations on condition for situational awareness. If the Radford Line is energized, shift loads to the Shay Line. Four hours prior to SCE de-energizing the lines, per the Field Operations Supervisor's direction, perform the following: Start up all BVPP enginators. Reduce system load to within the capacity of BVPP by isolating distribution circuits as directed by the Field Operations Supervisor. Once system load is matched with BVPP capacity, open the Shay and Baldwin automatic reclosers. Implement BVES EDRP for sustained loss of all SCE supply lines including "rolling blackout" procedures.

Section 5 of the attached PSPS Plan outlines the PSPS protocols, which includes the tactical and strategic decision for initiating a PSPS/de-energization. Section 4 describes the conditions that could lead to a PSPS enactment, and Section 2 describes the chain of command for initiating a PSPS event.

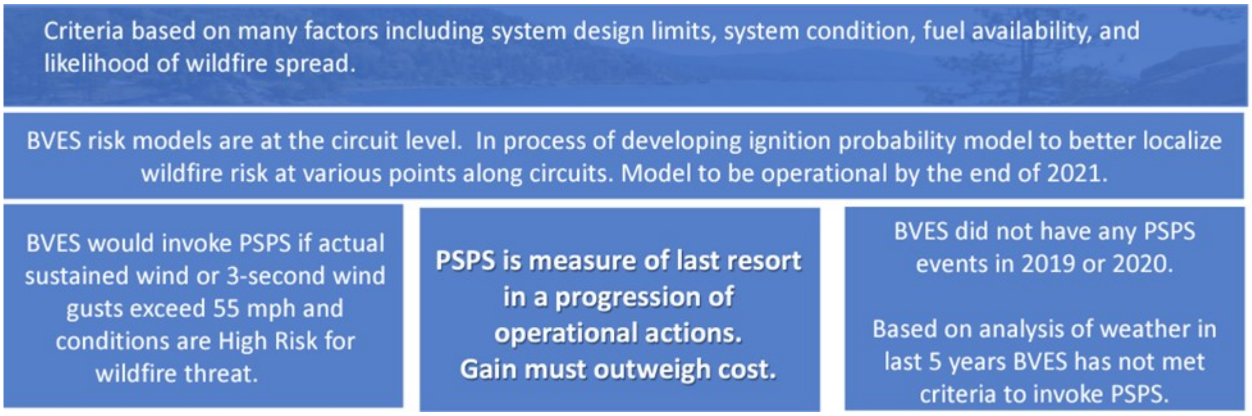


Figure 9-3 PSPS Decision-Making Criteria

In summary, BVES considers the following when determining conditions that would meet or exceed thresholds for de-energization:

- Design strength and other characteristics of distribution overhead facilities,
- Vegetation density,
- NFDRS for 7-day fire threat outlook,
- NWS advisories,
- Local weather forecasts and advisories,
- BVES meteorologist's forecast,
- Information from BVES installed weather stations,
- Real-time information from trained personnel positioned in high-risk areas, and
- Input from state and local authorities and Emergency Management Personnel.

"Extreme fire weather conditions" are deemed to be forecasted or exist when the NFDRS forecast is "red," "orange," or "brown," high winds (45 mph or greater) are forecasted or measured, and the BVES meteorologist forecasts high fire threat conditions. Once it is determined that "extreme fire weather conditions" are forecasted or exist, BVES Staff will implement BVES PSPS Procedures at the direction of the Utility Manager.

Protocols for mitigating the public safety impacts of PSPS, including impacts on first responders, health care facilities, operators of telecommunications infrastructure, and water electrical corporations/agencies

Section 6 of the PSPS Plan describes BVES's communication protocols designed to mitigate the public safety impacts of PSPS on the community. Due to the significant impact that a PSPS event may have on the community and customers, it is essential that early and accurate communications be conducted throughout the PSPS event coincides with local government, agencies, partner organizations (including emergency management community and first responders, CALOES, county and local governments, independent living centers, and representatives of people/communities with access and functional needs), and customers. BVES takes additional steps to ensure that vulnerable, marginalized, and at-risk communities are sufficiently informed of PSPS activities and wildfire outreach. As part of its public outreach, BVES is working towards increasing representation of people with AFN, senior citizen groups, business owners, and public health and healthcare providers including those with medical needs. This includes a CRC and communications regarding PSPS.

BVES, in collaboration with its contract public relations firm has also implemented new plans to further enhance its ability to engage vulnerable individuals and communities. Working with this firm, BVES will continue its prior communication methods and attempt to establish new forms to better identify and engage with its marginalized and at-risk individuals and communities. This includes issuing a bifold/postcard (or similar mailer) in both Spanish and English via mail carrier to its residents. This mailer was also made available on BVES's website in the other top identified languages of French, Tagalog, Vietnamese, and Chinese, as well as languages spoken by indigenous communities, such as Mixteco and Zapoteco. BVES also conducted a non-contact electronic survey regarding its WMP outreach and has made the results of the survey available in English and Spanish on its website. Finally, BVES has implemented and began utilizing newly acquired two-way texting capabilities to notify BVES customers about PSPS events or other emergencies.

BVES's efforts since January 1, 2022 include the following:

- Increased social media posts regarding AFN education and how to self-identify
- Created and uploaded an AFN informational video on BVES's social media platforms and website
- Added AFN self-identification letter to the BVES website
- Entered into a confidentiality agreement to share BVES's AFN and Medical Baseline population with the City of Big Bear Lake and the local fire agencies
- Added additional CRC information and accommodations to the website
- Implemented a PSPS portal for critical facilities and community-based organizations
- Updated the AFN application to be available in English and Spanish on BVES's website
- Trained customer service representatives to inquire on all calls about potentially AFN-eligible members in customer households
- Purchased portable batteries for PSPS events that are reserved for Medical Baseline and AFN community members

A small number of BVES customers reside in mobile home parks or in multi-unit residences that have electric master meters. Among these customers, BVES identified five locations to include in its medical baseline tracking sheets. Since July 1, 2022, BVES has been including AFN applications in English and Spanish, CARE applications, Medical Baseline applications, and informational flyers on PSPS and its CRC for master metered property owners and their tenants.

Specific details on how BVES engages with communities is outlined below:

BVES hosts and advertises its end-of-year public meeting where WMP, PSPS, and reliability plans are presented through local radio and newspaper. BVES will ensure its website is updated and contains the current WMP and associated video. BVES also uses Facebook to regularly distribute the WMP including the WMP's identified equipment upgrades, vegetation management, and operational improvements. Finally, BVES issues newsletters that include information regarding the WMP and PSPS plans. BVES will ensure all communications and outreach portals will be maintained in English.

BVES, in collaboration with its contract public relations firm, has also implemented new plans to further enhance its ability to engage vulnerable individuals and communities. Working with this firm, BVES will continue its prior communication methods and establish new forms to endeavor to identify and engage with its marginalized and at-risk communities. This included issuing communications in both Spanish and English; as applicable, via mail carrier to its identified customers. This mailer was also made available on BVES's website in the other top identified languages of French, Tagalog, Vietnamese, and Chinese, as well as languages spoken by indigenous communities not in BVES's service territory, such as Mixteco and Zapoteco. BVES also conducted a non-contact electronic survey regarding its WMP outreach and has made the results of the survey available in English and Spanish on its website. Finally, BVES has implemented and began utilizing newly acquired two-way texting capabilities to notify BVES customers about PSPS events or other emergencies.

See example tracking reports for communications delivered throughout 2022. Additional detail is provided in BVES's 2020 and 2021 Wildfire Mitigation Community Outreach Survey Results. BVES conducted two surveys in 2022, to evaluate the effectiveness of its outreach efforts. A total of 423 surveys were completed which included 30 from critical customers. The results are as follows:

- 46% of BVES customers surveyed are aware of wildfire safety communications.
- 41% recall seeing, hearing or reading the phrase, "Public Safety Power Shutoff or PSPS."
- 41% say they would first turn to BVES website for information about a PSPS event.
- 81% have taken action to prevent wildfires or to prepare their home or business.
- 48% are aware of BVES's efforts to prune vegetation.
- 43% are aware they can update their contact information with BVES.
- 83% of those surveyed can be considered AFN.
- 98% indicated it would not be helpful to receive communications in a language other than English.

9.3 Communication Strategy for PSPS

In Section 8.4.4 of the WMP, the electrical corporation must discuss all public communication strategies for wildfires, outages due to wildfires and PSPS, and service restoration. Thus, in this section, the electrical corporation is only required to provide a cross-reference to Section 8.4.4 and any other section of the WMP providing details of the emergency public communication strategy for PSPS implementation.

BVES discusses in detail all public communication strategies for outages due to wildfires and PSPS as well as service restoration in Section 8.4.4 of this WMP. Additionally, Table 6-1 of the

BVES PSPS Plan contains a comprehensive template outlining the communications plan for notifying the public and key partners during a potential PSPS activation.

9.4 Key Personnel, Qualifications, and Training for PSPS

In Section 8.4.2.2 of the WMP, the electrical corporation must discuss all key personnel planning, qualifications, and training for wildfires, outages due to wildfires, and PSPS, and service restoration. Thus, in this section, the electrical corporation is only required to provide a cross-reference to Section 8.4.2.2 and any other section of the WMP providing details of key personnel, qualifications, and training for PSPS implementation.

BVES discusses in detail the key personnel, planning, qualifications, and training for wildfires, outages due to wildfires, and PSPS, and service restoration in Section 8.4.2.2 of this WMP. Please refer to this section for details. Additionally, section 2 of the PSPS Plan describes the Chain of Responsibility during a PSPS and detail on assigned personnel and their roles.

9.5 Planning and Allocation of Resources for Service Restoration due to PSPS

In Section 8.4.5.2 of the WMP, the electrical corporation must address planning of appropriate resources (e.g., equipment, specialized workers) and allocation of those resources to assure the safety of the public during service restoration. Thus, in this section, the electrical corporation is only required to provide a cross-reference to Section 8.4.5.2 and any other section of the WMP providing details of resource planning for PSPS implementation.

Section 4.9 of BVES's PSPS Plan describes the internal strategy to safely re-energize any area that was de-energized as part of a PSPS event. Restoration may take place when wind speeds in the affected area where PSPS was invoked fall below 50 mph for a minimum period of 20 minutes, and crews assess that the fire weather conditions have subsided to "safe levels." However, the crews may extend the calm period beyond 20 minutes, if they assess further gusts of greater than 50 mph are likely based on direct observation of local conditions or forecasts indicate a high probability of winds picking up to greater than 50 mph. Crews are to 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: 1) validating that the extreme fire weather conditions have subsided, 2) conducting field inspections and patrols of facilities that were de-energized, and 3) re-energization of inspected (and repaired, if necessary) circuits. See the table below for additional detail.

Additional information can be found in Section 8.4.5.2 of this WMP.

Table 9-11 PSPS Re-energization and Post Event Strategy

PSPS Activity	Phase Event	Internal Action	External Coordination
Restoration	**Re-energization** (Extreme fire conditions subside to	**Operations & Planning:** Field Crews validate that the extreme fire weather conditions have subsided to	**Local Government, Agencies, and Partner Organizations:** Send "Intent to Restore" notice to local government, agencies, and partner

PSPS Activity	Phase Event	Internal Action	External Coordination
	safe levels as validated by field conditions)	safe levels as designated by the Field Operations Supervisor and report these conditions to Dispatch. Field Crews conduct field inspections and patrols of facilities that were de-energized. When field inspections and patrols are completed satisfactorily, power is restored to the affected circuits. As SCE restores supply lines, Field Crews conduct switching operations as directed by Field Operations Supervisor to restore systems normal. **Customer Service:** Finalize "Intent to Restore" notice to include ETR(s) 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	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. Update Stakeholders Portal **Customer Outreach:** Post "Intent to Restore" notice on BVES website and social media. Issue "Intent to Restore" press release for local media. Send out "Intent to Restore" notice via IVR. Send out "Intent to Restore" notice via Text Send out "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

PSPS Activity	Phase Event	Internal Action	External Coordination
		all equipment and supplies Prepare post-event reports Update Stakeholders Portal	an update if restoration is delayed. Send out "Restoration Complete" notice via IVR once power is fully restored or an update if restoration is delayed. Send out "Restoration Complete" notice via Text once power is fully restored or an update if restoration is delayed. Send out "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:** Utility Manager conduct lessons learned with applicable staff. Include Customer Service and solicit input from Local Government, Agencies, and Partner Organizations. If applicable, update plan and procedures per the lessons learned. Prepare PSPS Post Event Report required by ESRB-8 and forward to President and Manager Regulatory Affairs for approval.	**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.

10. Lessons Learned

An electrical corporation must use lessons learned to drive continuous improvement in its WMP. Electrical corporations must include lessons learned due to ongoing monitoring and evaluation initiatives, collaboration with other electrical corporations and industry experts, and feedback from Energy Safety and other regulators.

The electrical corporation must provide a summary of new lessons learned since its most recent WMP submission, and any ongoing improvements to address existing lessons learned. This must include a brief narrative describing the new key lessons learned and a status update on any ongoing improvements due to existing lessons learned. The narrative should be limited to two pages.

The electrical corporation must also provide a summary of how it continuously monitors and evaluates its wildfire mitigation efforts to identify lessons learned. This must include various policies, programs, and procedures for incorporating feedback to make improvements.

Lessons learned can be divided into the three main categories: (1) internal monitoring and evaluation, (2) external collaboration with other electrical corporations, and (3) feedback from Energy Safety or other authoritative bodies. The following are examples of specific potential sources of lessons learned:

- *Internal monitoring and evaluation initiatives:*
  - *Tracking of risk events*
  - *Findings from root cause analyses and after-action reviews*
  - *Drills and exercises*
  - *Feedback from community engagement*
  - *PSPS events*
- *Feedback from Energy Safety or other authoritative bodies:*
  - *Areas for continued improvement identified by Energy Safety in the previous WMP evaluation period*
  - *Findings from wildfire investigations*
  - *Findings from Energy Safety Compliance Division assessments*
  - *Collaborations with other electrical corporations*

In addition to the above potential sources of lessons learned, the electric corporation must detail lessons learned from any and each catastrophic wildfire ignited by its facilities or equipment in the past 20 years, as listed in Section 5.3.2. The electric corporation must also detail specific mitigation measures implemented as a result of these lessons learned and demonstrate how the mitigation measures are being integrated into the electric corporation's wildfire mitigation strategy.

For each lesson learned, the electrical corporation must identify the following in Table 10-1:

- *Year the lesson learned was identified*
- *Subject of the lesson learned*
- *Specific type or source of lesson learned (as identified in the bullet lists above)*
- *Brief description of the lesson learned that informed improvement to the WMP*

- *Brief description of the proposed improvement to the WMP and which initiative(s) or activity(s) the electrical corporation intends to add or modify*
- *Estimated timeline for implementing the proposed improvement*
- *Reference to the documentation that describes and substantiates the need for improvement including:*
    - *Where relevant, a hyperlinked section and page number in the appendix of the WMP*
    - *Where relevant, the title of the report, date of report, and link to the electrical corporation web page where the report can be downloaded*
    - *If any lessons learned were derived from quantifiable data, visual/graphical representations of these lessons learned in the supporting documentation*

The 2023 WMP Update includes reports on actions undertaken over 2022 including activities relating to any deficiencies issued by the OEIS, including lessons learned from BVES and its peer utilities. In addition, the Plan has evolved significantly over the 2020, 2021, and 2022 WMP Update submissions through new templatized processes, enhanced data collection and governance, and successful execution of high priority initiatives.

BVES has worked to make updates to its quantitative target setting to align with prioritized mitigation efforts. The 2023 WMP Update includes improvements such as enhanced mapping 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 a concern 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. BVES experienced success in executing and implementing mitigation strategies and has not recorded a utility-ignited wildfire incident or activated a PSPS. 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, Treasurer, & Secretary 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.

Table 10-1 provides a summary of lessons learned in 2020, 2021, and 2022 and corresponding changes in the BVES 2023 WMP Update.

Table 10-1 Lessons Learned

ID #	Year of Lesson Learned	Subject	Type or Source of Lesson Learned	Description of Lesson Learned	Proposed WMP Improvement	Timeline for Implementation	Reference
01	2020 / 2021		Resource Allocation Methodology	Internal and external resources are required to fill key roles for WMP implementation	BVES hired direct roles to oversee prioritized aspects of the WMP program and processes. However, external consultant support is still a necessity for some areas.		
02	2020 / 2021		Situational Awareness, Grid Design and System Hardening	External constraints related to federally managed or private lands impact initiative schedules and implementation and require active management	Execution of system hardening, and situational awareness initiatives resulted in some minor delays over the 2020-21 timeframe. For example, BVES was able to complete the last two weather station installations in early 2021 after significant delays. Similarly, BVES has pushed out the schedule for its energy storage project due to land siting issues.		
03	2020 / 2021		Grid Design and System Hardening	Replicated initiatives among California IOUs on	BVES has worked to better account for its mitigation measures		

				similar time schedules causes material procurement delays and increased costs for system hardening initiatives such as covered conductor hardening	under varying WMP mitigation category initiative listings, which results in slight deviations from planned expenditure. These issues are addressed by a revised accounting methodology that has been applied to align to the latest OEIS issued initiative listing. BVES has moved to a year-ahead purchasing schedule for system hardening stock based on initiative efficiencies and historic replacement trends. Projections on stock have also improved.		
04	2020 / 2021		Grid Design and System Hardening	Winter months snow loading requires careful planning of field work	Due to the topography and climate of the region, BVES experiences seasonal delays due to inability to perform field work during winter weather conditions. As substantive mitigation measures are deployed within the earlier years of the WMP program, this concern will lessen,		

					and strategic operations can be better refined to avoid such harsh winter conditions.		
05	2020 / 2021		Risk Assessment and Mapping	Determination of quantitatively driven metrics and risk spend efficiency (RSE) values are needed to adequately measure initiative effectiveness for existing and enhanced technologies	BVES was not able to update all its RSE values in 2021 within the quarterly data report (QDR) updates due to initiative recategorization and lack of sustained metrics, which result in meaningful baseline data metrics.		
06	2020 / 2021		Risk Assessment and Mapping	Determination of quantitatively driven metrics and RSE values are needed to adequately measure initiative effectiveness for existing and enhanced technologies	BVES has deployed grid hardening activities on prioritized circuits to reduce future risk events. The intent is to lower the number of risk events captured in the QDR metrics as demonstrated spark-resistant measures are applied to the system (e.g., number of blown fuse events recorded over time). BVES completed its program to replace all conventional fuses with current limiting		Error! Reference source not found.

					and electronic fuses. The resulting metrics indicate this effort is already reducing blown fuse events, a significant ignition risk factor.		
07	2020 / 2021		Risk Assessment and Mapping	Determination of quantitatively driven metrics and RSE values are needed to adequately measure initiative effectiveness for existing and enhanced technologies	BVES works in its third year of hardening efforts. Overall risk events have not begun to indicate a downward trend in activity, apart from blown fuse tracking. The anticipated result fewer risk events on the system year over year. Risk predictions and recorded incidents determine the baseline and BVES will track these metrics for future WMP updates.		Error! Reference source not found.
08	2020 / 2021		Risk Assessment and Mapping	Determination of quantitatively driven metrics and RSE values are needed to adequately measure initiative effectiveness for existing and enhanced technologies	BVES has replaced an increased number of poles and determined needs for fire resistant wrapping as inspection programs are carried out. Metrics do not indicate a meaningfully scaled trend, but they do convey increased intrusive inspections of poles for remediation		Error! Reference source not found.

					or replacement, for which BVES has met its internal targets.		
09	2020 / 2021		Risk Assessment and Mapping	Improved data tracking, equipment inventorying practices, and refined definitions for specific metrics leads to instances of impacted quantitative metrics	In preparation for this filing, BVES reviewed the completed 2021 metrics, as well as its projects initiated to mitigate against wildfire ignitions and damage to BVES equipment and facilities, to determine whether current scheduling and planned execution is sufficient in its 2022 WMP Update. BVES has also been able to achieve greater granularity in weather data with no identified increase in severe weather. Due to better data tracking, equipment inventory practices, and refined definitions for specific metrics, BVES has seen instances of impacted quantitative metrics from 2020 to 2021. In years prior, BVES had not been able to effectively leverage existing data.		

10	2020 / 2021		Risk Assessment and Mapping	The ignition risk and consequence mapping project has provided useful insight into simulations of fire threats	The modeling exercise will influence future planning as current initiatives are carried out. The models and maps were finalized in late 2021, providing an initial screening into areas of greatest concern beyond the high fire-threat district (HFTD) and wildland urban interface (WUI) designations. In future reporting and mitigation measure determination, these maps will contribute to navigate decision-making along with existing risk modeling tools.		
11	2020 / 2021		Stakeholder Cooperation and Community Engagement	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.		
13	2022		Tracking of Risk Events	The need for BVES to follow more	No direct link to WMP	N/A	

				closely the Emergency Response Disaster Plan (EDRP)			
14	2022		Drills and Exercises and the associated Community Engagement	The feedback from Drills and Exercise is vital to the advancement of BVES programs, specifically those related to PSPS	Actions Taken in 2022: (1) BVES improved its coordinated communication with external parties, partners, and agencies by maintaining its PSPS portal and verifying key contact lists in advance of the wildfire season, (2) increased exercise complexity and interaction, (3) provided additional backup training for various emergency roles and levels or responsibilities, and (4) prepared for both in-person and remote work emergencies.		
15	2022		Continued Improvement per Energy Safety Guidance	More detail and more identifiers in its customer database would benefit BVES Energy Safety Advised BVES to make updates in its Spatial Data to	Both these items apply to Customer Outreach and Emergency Response. No direct connection to WMP but guided changes to internal BVES plans. Per Energy Safety request, BVES added	2022	

				include more information for clarity and granularity	flags in November 2022 to the Customer Data Base regarding customers with security or access concerns. This allows BVES to know ahead of time if there are concerns when entering a customer sight. Per discussions with Energy Safety, the Spatial Data was upgraded in the 2022 QDRs to include INITIATIVES (Grid Hardening, Vegetation Management, Asset Inspections, Vegetation Inspections) and FEATURE CLASSES (Switchgears, Transformer Sites, Primary Distribution Lines, Support Structures, Unplanned Outages, Lightning Arrestors).		
16	2022		Covered Conductor Working Group	The utilities agree that it is helpful to share information, practices, and data across the utilities	General review of communication plans/targets for the 2023 cycle		

				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.			
17	2022		Risk Model Working Group	The Risk Model Working Group has provided BVES with significant amount of detailed information concerning Risk Modeling especially from the Large Utilities which utilize more detailed modeling than BVES.	The information gained can help shape how BVES uses its risk modeling resources and makes decisions moving forward.		

11. Corrective Action Program

In this section, the electrical corporation must describe its corrective action program. The electrical corporation must present a summary description of the relevant portions of its existing procedures.

The electrical corporation must report on how it maintains a corrective action program to track formal actions and activities undertaken to:

- *Prevent recurrence of risk events*
- *Address findings from wildfire investigations (both internal and external)*
- *Address findings from Energy Safety's Compliance Assurance Division (i.e., audits and notices of defect and violation)*
- *Address areas for continued improvement identified by Energy Safety as part of the WMP evaluation*

The electrical corporation must report on how it reviews each improvement area in accordance with its corrective action program. At a minimum, the electrical corporation must:

- *Identify insufficient occurrence and response: Identify targeted corrective actions for areas where the event occurrence, response, or feature was insufficient.*
- *Identify actions to reduce recurrence: Identify improvement actions (as applicable) to reduce the likelihood of recurrence, improve response/mitigation actions, or improve operational procedures or practices.*
- *Track implementation: Track the improvement action plan and schedule in the electrical corporation's action tracking system.*
- *Improve external communication: For areas where weaknesses were identified in the response of external agencies, develop a communication plan to share the information and conclusion with the responsible agency. The completion of this action and the agency's response must be documented.*
- *Integrate lessons learned from across the industry: Identify applicable generic lessons learned to improve the overall effectiveness of the electrical corporation WMP.*
- *Share lessons learned with others: Identify and communicate any significant generic lessons learned that should be disseminated broadly (i.e., to other electrical corporations and responsible regulatory authorities, such as Energy Safety or CAL FIRE).*

The WMP should not include detailed corrective action plans for each risk event, finding, and/or improvement area. However, this documentation must be made available to Energy Safety upon request.

In 2022 there were no audits or related findings from Energy Safety or Internal/External Investigations. It is BVES's policy to address all results of investigation (Internal, External, Energy Safety Compliance Assurance Division) within the window enforced by the discovering party. BVES does, however, prioritize audit findings requiring a corrective action plan. Any corrective action plan requiring an extended timeline to address would be tracked and monitored through a project plan.

BVES maintains documented plans for follow up and continuing to ensure that continuous improvement efforts incorporate any lessons learned. For example, BVES contracts with BSI, a group of safety consultants, to review and update safety procedures and ensure they are in accordance with current best practices and standards. BVES also adheres to FEMA's 6-step planning process as preparation for and review of any event and ensures there is a thorough debrief following an event to capture lessons learned.

Energy Safety provided feedback on BVES's 2022 WMP in its decision letter. The items identified, progress and updates from that feedback are in Table 11-1 below.

Table 11-1 2022 WMP Feedback and Status

Issue #	Title	Status	Comments
BVES 21-07	Lack of detail on prioritization of initiatives based on determined risk	Improving maturity on tracking for this initiative, improvements expected by 2023.	With the change in WMP template and differing requested information, BVES believes that Section 6 & 7 of the current WMP provide detail to support assessment of previous WMP issue
BVES-21-09	Lack of asset inspection quality assurance and quality control (QA/QC) program	BVES has been working to improve the maturity of the asset inspection quality assurance and quality control program by 2023. Specifically, BVES is focusing on the following areas: - BVES plans to schedule patrol, detailed, and other inspections based on modeling and risk assessments. - BVES plans to include lines and equipment typically responsible for ignitions and near misses in its inspection procedures and checklists, as opposed to only items required by statute and regulations. - BVES plans to base procedures and checklists on predictive modeling and to increase the granularity from a service territory to a circuit level. - BVES plans to include performance history and past operating conditions when accounting for maintenance and repair procedures.	BVES accelerated implementation and improved its asset inspection QA/QC programs and continues to demonstrate progress in section 8.1.4. It is important to note that BVES has now fully implemented its QA/QC program and is no longer operating on a “interim” program

RN-BVES-22-03	BVES has not sufficiently connected its risk assessment with its mitigation initiative prioritization	Continuing to monitor the below efforts: a) Integrate its response to BVES-21-07, found in Appendix A, into WMP Section 7.3.3 "Grid Design and System Hardening." b) Demonstrate that its risk assessments directly inform the prioritization of initiatives, instead of broadly stating that risk is a consideration or defaulting prioritization to only HTFD Tier 2 and Tier 3 designations. c) Demonstrate that its future planned grid hardening mitigation initiatives, particularly covered conductor, will address the highest risk circuits as self-assessed and identified by BVES and its relevant contractor(s). d) Describe how it selected the location of its covered conductor pilot program.	BVES improved its initiative prioritization program in 2022 and better aligned it with the risks presented in its service territory. This is presented in Sections 6 & 7. BVES has recently implemented Technosylva's WRRM, which will be the primary risk model for prioritizing WMP initiatives in BVES's 2024 WMP Update. Furthermore, in BVES's 2024 WMP Update, it expects to have calculated likelihood and consequence for relevant risks.
RN-BVES-22-04	BVES has not provided sufficient information on quality assurance & quality control (QA/QC)	BVES was required to: a) Provide details on progress made developing and implementing its formal QA/QC process, including implementation timing. b) Provide results of the "interim" QA/QC processes BVES has used for assets, including details on what type of QA/QC was performed, the percentage of asset inspections on which BVES completed QA/QC, and the results of the QA/QC performed since the 2021 Update.	BVES accelerated implementation and improved its QA/QC programs and continues to demonstrate progress in section 8.1.4 & 8.2.5.

RN-BVES-22-06	BVES has misinterpreted data management initiatives	BVES was required to describe how it currently manages all data relevant to wildfire mitigation and any planned or ongoing improvements to these systems, in accordance with the 2022 WMP Guidelines. BVES should not limit the discussion to the provision of quarterly spatial data required by Energy Safety.	BVES continues to improve its data management for asset and vegetation management through iRestore, its GIS program, Technosylva, and other tools to better track, monitor, and share key WMP data. BVES is evolving its programs to an enterprise system with spatial capability.
RN-BVES-22-07	BVES does not describe how quantifiable risk reductions and RSE estimates inform initiative selection	BVES was required to provide: a) An overview of its decision-making framework that includes the rankings of relative decision-making factors (e.g., planning and execution lead times, resource constraints, etc.) and pinpoints where quantifiable risk reductions and RSE estimates are considered in the initiative selection process. b) A cascading, dynamic “if-then” style flow chart to effectively demonstrate this prioritization process.	See discussion above in response to RN-BVES-22-03.
RN-BVES-22-10	BVES does not describe how its PSPS planning has evolved	BVES was required to: a) Provide more information to describe how its planning has evolved, as specified by Section 8.3 of the Guidelines. This should include lessons learned from other utilities and internal exercises, and how those were used to update its PSPS Plan. b) File a revised PSPS Plan within 30 days of Energy Safety’s Decision on BVES’s 2022 Update integrating the requirements of D.21-06-034.53.	BVES files a revised PSPS Plan in 2022 fulfilling the request of RN-BVES-22-10 as well as meeting Phase III requirements. This is also addressed in sections 8.4 and 9 of this WMP.

BVES is involved with and participates in several working groups to gather and share lessons learned and best practices across a variety of topics and specialty areas. Individual personnel are assigned to participate in each group and will report back any applicable information for consideration in future improvements. A full list of the working groups and their respective updates or subject matter can be found below in Table 11-2.

Table 11-2 Working Groups

Working Group Title	Description
Covered Conductor Working Group (and multiple sub-working groups)	Utilities meet to discuss the effectiveness and alternatives to covered conductors. Several sub-working groups meet to for detailed discussions on specific topics.
Risk Modeling Working Group	Utilities, Energy Safety, and industry experts meet to discuss ideas and methods on how to improve modeling which evaluates wildfire risk.
Utilities Best Learn from Each Other Working Group	Working Group will begin in 2023. The working group will discuss lessons learned to help disseminate useful information throughout the industry.
Electric Vehicle Working Group.	Utilities meet to discuss electric vehicle technologies.

12. Notice of Violation and Defect

Within a Notice of Violation (NOV) or Notice of Defect (NOD), Energy Safety directs an electrical corporation to correct a violation or defect within a specific timeline, depending on the risk category of the violation or defect. The electrical corporation has 30 days to respond to the NOV or NOD and provide a plan for corrective action. Following completion of corrective action, the electrical corporation must provide Energy Safety with documentation validating the resolution or correction of the identified violation or defect. Energy Safety includes the electrical corporation's response and the resolution status of any violations or defects in the summaries it provides to the CPUC.

In Table 12-1 of the WMP, the electrical corporation must provide a list of all open violations and defect

BVES does not currently have any open Notice of Violation (NOV) or Notice of Defect (NOD). To date, BVES has not received an NOV or NOD. If and when, BVES receives an NOV or NOD, appropriate and timely corrective actions will be taken, and the associated documentation needs will be met.

Table 12-1 Open Violations and Defects

ID	Type	Severity	Date of Notice	Date of Response	Summary Description of Violation/Defect	Estimated Completion Date	Summary Description of Correction
N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

Appendix A.

Appendix B.

Appendix C.

Appendix D.